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Water Levels Reference Study. Phase 1. Electric Power Work Group Report

International Joint Commission. Functional Group 3. Work Group 7

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ELECTRIC POWER WORK GROUP REPORT

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INTERNATIONAL JOINT COMMISSION
WATER LEVELS REFERENCE STUDY

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FG3-SOCIO-ECONOMIC AND ENVIRONMENTAL COMMITTEE

ELECTRIC POWER WORK GROUP

EXECUTIVE SUMMARY

The electric power industry consists of utilities and non-utility companies that generate the electric power, and bodies such as regional reliability councils and local power pools, that coordinate planning, design, forecasts of energy needs and the transfer of power between generating companies. A particular utility or non-utility company may generate electricity using hydropower, thermal power (coal, oil, natural gas, nuclear) or a combination of both. Power can be transferred between utilities via transmission lines, the amount depending on demand, availability and transmission line capacity.

Approximately 94400 mW of power could be impacted in some way by fluctuating levels and flows. This represents 33% of the total installed capacity within the four regional reliability councils that have a border on the Great Lakes.

Hydropower outputs in general can be increased with increasing levels and flows, although there is a threshold of extreme highs above which extra flow cannot be utilized due to physical limitations of equipment and/or hydraulic limitations. During high water periods, thermal power facilities could experience greater generating efficiency due to lower temperatures of cooling water. Pumping and transportation costs also could be reduced. Extreme high levels, or average levels with more extreme fluctuations, can cause flooding of some facilities.

Impacts would be more severe during below average levels and flows. Hydropower production would be reduced. These shortfalls in power can be made up by more expensive thermal power, as long as the decrease in hydropower capacity is not large and demand does not increase significantly.

Thermal power plants may be negatively affected by lower levels and flows, particularly if the plant relies on delivery of fuel by water-borne transport (lake freighter or river barge). The cost of fuel delivery might increase if shipping capacity is reduced and if more dredging is required. Furthermore, generating capacity at thermal plants is reduced by warmer cooling water temperatures. The cooling water drawn from the Great Lakes, connecting channels and tributaries, probably would be warmer under a lower level and flow/drought scenario.

Power shortages could result under a prolonged drought scenario and utilities generally do not have a drought contingency plan. Transmission limitations would not enable a given utility to entirely make up drought-induced shortfalls through power imports. It also is unlikely that other utilities would have excess power to sell during a widespread drought.

Regardless, any reduction in installed hydropower capacity, resulting in increased thermal power production, will have a negative impact on the environment. For example, the environment could be negatively affected due to: increased emissions of "greenhouse" gases (NOx, COx, SOx) and other atmospheric pollutants (eg. selenium), thermal pollution from cooling water discharge, and the increased need to dispose of solid wastes such as fly ash and spent nuclear fuel.

Structural measures such as 50N probably would do little to ameliorate the adverse consequences associated with extreme low levels and flows. It would be of value to actively develop and encourage non-structural management measures, such as conservation and off peak usage.

In summary, within a range of fluctuations around long term averages, the interests can reliably generate electric power to meet current demands with attendant environmental, economic and social impacts.

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1. BACKGROUND

1.1 Authority

On August 1, 1986, the Governments of the United States and Canada forwarded a "Great Lakes Levels Reference" to the International Joint Commission (IJC) pursuant to Article IX of the Boundary Waters Treaty of 1909. This Reference requests the IJC to examine and report upon methods of alleviating the adverse consequences of fluctuating water levels in the Great Lakes-St. Lawrence River (GL/SLR) Basin. The IJC issued a Directive concerning this Reference on April 10, 1987, which outlined the IJC's plan to respond to the Reference. A Background Paper dated November 2, 1987, also has been prepared and is available to the public as a comprehensive guide to the goals, objectives, and methods for the study.

1.2 Objectives

The primary objectives of the Reference are to establish an analytical capability by which Governments collectively can make decisions to deal with fluctuating water level conditions and identify and analyze certain measures as a basis for bi-national consideration of possible implementation of those measures. As part of this comprehensive effort, the Electric Power Working Group defined and assessed the complex and interrelated problems the electric power industry has experienced and is expected to experience due to lake level fluctuations. The effects of levels and flows higher and lower than those experienced historically also were determined. Changes in economic conditions and improvements in analytical techniques that have developed since the completion of previous studies and reports have been factored into the evaluation.

1.3 Scope

The study by the Electric Power Work Group has expanded upon previous studies and emphasizes:

a. An expanded geographical scope that includes the Great Lakes Basin and any surrounding areas that may be affected through interconnection of electrical distribution systems.

b. An expanded recognition of the interdependence of the environment (hydrology, ecology, etc.) and man's uses of and needs for electric power.

c. An expanded recognition of the interaction between the electric utility industry, their customers, the natural resources that support them, and the economy.

d. An expanded consideration of the effects of proposed measures on the electric power interest groups.

e. Consideration of improvements in providing public information relative to the effects of proposed measures on electric power interest groups.

f. Expanded consideration of the institutional requirements and procedures for implementation of measures that may or may not affect the electric power interest groups.

g. Expanded consideration of impacts of measures on electric power over the full range of probable lake levels and flows.

1.4 Study Elements

The IJC Reference will be conducted in two phases and the tasks to be accomplished by the Electric Power Working Group include:

a. Phase I

1) Characterize the level and flow fluctuations and their consequences on the electric power interest groups.
2) Assist in developing a comprehensive inventory of measures that could alleviate the impacts of fluctuating levels and flows.
3) Develop a systematic and comprehensive qualitative framework for evaluating the effects of measures, including models.
4) Assist in developing a preliminary Information Program about the effects of the various measures on the electric power interest groups for use by the Governments.
5) Begin compiling an electric power database.
6) Assist in writing a Phase I Report.

b. Phase II

1) Refine information contained in the electric power database.
2) Conduct detailed qualitative/quantitative evaluations of selected measures using tools and/or models developed in Phase I.
3) Assist in designing a final Information Program for use by the Governments
4) Assist in writing a Phase II report.

This Phase I report will be the basis for the application of the evaluation framework, culminating with the Phase II report to be released in September 1991.

1.5 Contacts

The following individuals comprise the present WG7 membership:

a. Bradford S. Price, U.S. Army Corps of Engineers, Buffalo, N.Y. (716) 876-5454, ext. 2260.
b. Robert B. Chang, Ontario Ministry of Natural Resources, Toronto, Ontario (416) 965-6295.
c. Ronald J. Guido, U.S. Army Corps of Engineers, Buffalo, N.Y. (716) 876-5454, ext. 2177.
d. Thomas Muir, Environment Canada, Burlington, Ontario (416) 336-4951.
e. Kim N. Irvine, U.S. Army Corps of Engineers, Buffalo, N.Y. (716) 876-5454, ext. 2260.

In addition, the individuals who provided assistance, information and advice during the course of this study are listed in Appendix A.

1.6 Review of Previous Reports

Several literature searches were conducted to compile a list of public and private studies, reports, and other available reference material dealing with electric power and its relationship to Great Lakes levels and flows. Additional information and literature were obtained through contacts with personnel in the electric utility industry, private organizations and the public. Most of the pertinent literature was obtained through these sources. A review of the available information has been accomplished. Appendix B contains the list of literature examined and pertinent information is referenced in the text using the Appendix B reference number in parentheses. In addition, a review has been done of past studies that examined the impacts of fluctuating water levels on the electric power industry (Section 4.2).

2. APPROACH OF THE WORK GROUP

2.1 Outline of General Study Approach

a. Identified primary hydropower interests to work as associates with the work group.

b. Held meetings with the work group associates to discuss the study, its objectives and tasks that the associates could perform. The associates (Appendix A) provided input to this paper, especially Sections 4,5,6, and 7.

c. Contacted the Department of Energy, Energy Information Office; Statistics Canada; individual utilities and the electric Regional Reliability Councils for information on power plants, including location, generating capacity, interconnections, types of fuel used, fuel origins, fuel destinations, mode of fuel transport. This information is presented in Appendices C, D, and L.

d. Performed a literature search through the Buffalo District librarian of the available studies of the impacts of fluctuating water levels on the electric utility industry. The literature is included in the references, Appendix B. The methodology and conclusions of several of these studies are reviewed in Section 4.2.

e. Performed a literature search through the Buffalo District librarian of the available models to assess impacts of fluctuating water levels on the electric utility industry.

f. Contacted and held meetings with representatives of the New York Power Pool (NYPP), Ontario Hydro and Hydro-Quebec to obtain information on industry operations and to determine the impacts of fluctuating levels on electric reliability (Appendix K).

g. Contacted representative thermal interests to obtain perceptions of impacts. A copy of the questionnaire circulated to Ontario Hydro, New York State Electric and Gas Corp. and Niagara Mohawk Power Corp. is presented in Appendix E.

h. Identified sub-class interests (Appendix M). Some of the identified sub-class interests were contacted to obtain their views regarding impacts of fluctuating water levels.

i. Successive drafts of the working paper were prepared based on input from work group members, associates and other sources.

3. DESCRIPTION OF THE INTEREST CLASS

3.1 Primary Interest Class

"Interests", in the context of the overall Water Levels Reference Study are defined as groups, including specialized mission agencies of governments, which (1) perceive that their constituents welfare is influenced by lake level fluctuation or policies and measures to address lake level fluctuation, and (2) are willing and able to enter the decision making process to protect the welfare of their constituents. The primary interest class is the electric power generating industry, whose constituents are its customers. A full list of the primary interests is given in Appendix L.

Hydropower plants owned by the primary interests use the levels and flows of the Great Lakes and connecting channels to generate electricity or indirectly as a source of water for pumped storage. Thermal power plants owned by the primary interests use the levels and flows of the Great Lakes and connecting channels for the transport of raw materials and as a source of cooling water. For the purposes of this study "thermal power" includes fossil and nuclear fuels, unless otherwise stated.

The electric power industry can be divided into two functional components; i) corporations that generate power; and ii) those bodies that coordinate power production and distribution. These two functional components can be further subdivided. Power generating corporations may be utilities or non-utilities. Utilities may be investor-owned (eg. Niagara Mohawk Power Corp., Rochester Gas and Electric Corp.), municipally or publicly owned (eg. New York Power Authority, Ontario Hydro, Hydro-Quebec) or a cooperative system (eg. Cloverland Electric Coop). Publicly owned utilities operate on a cost basis and not for the profit of private shareholders. Non-utility generators (NUGs) typically are investor-owned industries that have power generating capacity to service industrial processes. NUGs also may have the capability of selling excess electricity to utilities. NUG capacity is used by utilities in lieu of constructing additional, utility-owned generators. NUGs currently make up less than 3% of the generating capacity in the Great Lakes region (7, 34, Appendix L). A given utility or NUG may generate electricity using hydropower, thermal power or a combination of both.

Major utilities located throughout the Great Lakes Basin are interconnected by transmission lines and electricity can be "wheeled" to different areas, depending on demand and capacity limitations of the transmission lines. Local power pools coordinate the transfer or "wheeling" of electricity and assist in the development of energy forecasts (6). Regional Reliability Councils coordinate planning and design and prepare forecasts of energy needs in order to promote the reliability and efficiency of the electric supply (34, 51). The local pools and regional councils operate at different spatial scales and as a result have slightly different mandates.

The North American Electric Reliability Council (NERC) consists of nine Regional Reliability Councils and one affiliate that promote and evaluate reliability of the bulk electric system for most of North America (Appendix F). Reliability is defined as "the degree to which the performance of the elements of that [electric] system results in electricity being delivered to its customers within accepted standards and in the amount desired" (34). Four of the Regional Reliability Councils have a border on the Great Lakes (East Central Area Reliability Coordination Agreement (ECAR), North East Power Coordinating Council (NPCC), Mid-America Interconnected Network (MAIN), Mid-Continent Area Power Pool (MAPP))(see Appendix F). ECAR and NPCC account, respectively, for 33% and 39% (total 72%) of the power production within the four councils bordering the Great Lakes (34) and Phase I research efforts concentrated on utilities located in these two regions.

At a smaller spatial scale, power pools help to evaluate future power needs as well as coordinate power production and distribution. The New York Power Pool (NYPP) for example, "coordinates exchanges of power among interconnected power systems, detects problems and takes actions to correct them, monitors usage, records data and is responsible for transfers of bulk electric power from one system to another" (44). In addition, the NYPP aggregates and synthesizes the energy forecasts of its member utilities and evaluates the impacts that the New York electric industry has on the environment. The NYPP also is a member of the NPCC and provides the council with information about the status of power production in New York State.

The NYPP consists of 8 utilities: New York State Electric and Gas Corp., Niagara Mohawk Power Corp., Rochester Gas & Electric Corp., New York Power Authority, Orange and Rockland Utilities, Central Hudson Gas & Electric Corp., Consolidated Edison Company of New York, and Long Island Lighting Company. Together, the 8 utilities supply 99% of the electric energy needs in New York State and this also represents 27% of the NPCC capacity.

Individual utilities and NUGs do not necessarily belong to a power pool, but may supply electric power (through contract) to a utility within a power pool. The additional 1% of New York State energy needs, for example, would be met by utilities and NUGs that do not belong to the NYPP.

Electric power generating facilities sited on a lakefront, intuitively, would experience the greatest effects due to fluctuating lake levels. Levels and flows on tributaries generally would exhibit a similar temporal pattern to those of the Great Lakes, although they would respond to wet and dry periods more rapidly. Therefore, many of the electric generating facilities located on or near the Great Lakes would experience relatively similar hydrologic conditions. For these reasons, counties in the United States and Canada directly bordering the Great Lakes have been identified and an inventory of electric power plants in these counties has been compiled (Appendix L). This database is being maintained in spreadsheet format at the

Buffalo District Corps of Engineers. Approximately 94400 mW of power generated by thermal and hydropower plants located in counties bordering the Great Lakes could be affected by fluctuating water levels (Appendices C and L). This represents 33% of the total power capacity within the four Regional Reliability Councils that have a border on the Great Lakes.

Hydropower plants that directly or indirectly (ie. pumped storage facilities) use the levels and flows of the Great Lakes and connecting channels are, for the most part, located along the Niagara River (total capacity, 4500 mW), on the St. Mary's River at Sault Ste. Marie (total capacity, 101 mW) and on the St. Lawrence River (total capacity, 2720 mW)(2, 4, 9, 15). Collectively, these hydropower facilities represent 3% of the capacity within the four Regional Reliability Councils that have a border on the Great Lakes and 8% of the capacity in the counties bordering the Great Lakes. In addition, there are numerous small hydropower plants located on tributaries to the Great Lakes that could be impacted by widespread dry and wet conditions. In total, hydropower accounts for 22% of the capacity in counties bordering the Great Lakes and 7% of the capacity within the four Regional Reliability Councils that have a border on the Great Lakes (Appendix C). Furthermore, hydropower accounts for 31% of all NPCC power capacity, but less than approximately 4% of ECAR power capacity (34).

An inventory of first-link interconnections between major utilities and between Regional Reliability Councils has been compiled and results are presented in Appendices F, G, H and I. This inventory can be used to assess the ability of the system to transfer large blocks of power in the event that an interest could not meet its demand.

3.2 Interest Sub-classes

Sub-classes of the interest have been identified and include:

a. Customers that receive power generated by the primary interests (industry, municipal utilities, other utilities, and the public). They may not use the lakes directly but benefit directly from the power generated by the primary interest.

b. Companies located world wide that transport natural resources by water and land for use in generating electricity. They are directly concerned about how levels and flows may affect ability to transport commodities.

c. Companies located world wide that develop the natural resources used in electric power generation. These companies may not use the lakes directly but share the concerns expressed in b., above.

d. The workers located world wide, as represented by themselves or through collective bargaining units, that work primarily for the primary interest class and sub-classes identified above but also would include those listed below. Those involved in the water-borne commerce industry use the lakes directly. Others may not.

e. Governments that oversee the intrastate/province, interstate/province, and international transportation of electricity and natural resources used in generating electricity. They do not use the lakes directly but are concerned with such issues as balance of payments, regional, national and international shifts in resource use, prices of bulk power, etc.

f. Governments that establish rates for intrastate/province, interstate/province, and international transportation of electricity. They do not use the lakes directly. The Federal Energy Regulatory Commission (FERC) in the U.S., for example, oversees the rates charged for interstate transport of bulk power.

g. Environmental groups concerned with fish passage, thermal discharge effects upon fish and fauna, acid rain, spent nuclear fuel handling/storage, etc.

h. Consumer groups concerned with the cost of electric energy and the natural resources used in its generation.

i. Financial institutions concerned with the shift in the type of power generated and the effects upon investments in existing plant and equipment occasioned by low lake levels and changes in low levels due to implementation of measures.

j. Stockholders of investor-owned utilities that buy electricity generated from Great Lakes waters.

k. Recreation on tributary projects that may be adversely affected due to lowered levels resulting from higher releases to meet downstream water level needs.

l. Governments that collect "water rentals" for water used in generating power.

m. Public interest groups concerned with development of a comprehensive coastal management strategy that would include land and water use by electric power interests.

n. Private environmental engineering and research companies involved in waste management and production of technology for waste management.

4. SENSITIVITY OF THE INTEREST CLASSES TO WATER FLUCTUATIONS-DO NOTHING CONDITION

4.1 Introduction - An Overview of Possible Impacts of Water Fluctuations on Primary Interests

Section 4 focuses on the sensitivity of the interest classes to fluctuating water levels and identifies the possible impacts as they are perceived by the interest classes and the work group. Fluctuating lake levels may affect services from the lakes. An interest is considered sensitive to fluctuating lake levels if impacts (positive or negative) are incurred due to the fluctuation. Sensitivity and positive and negative impacts therefore are used synonymously in the following sections.

Discussions with primary interests (Appendix A) revealed that the implications of fluctuating levels and flows under the "do nothing condition" (without any measures other than those presently in place) are expected to be most severe during periods of below average levels and flows. During above average levels and flows most hydropower projects are able to meet contracted loads and even have excess (secondary) energy that can be sold for use in lieu of burning fossil fuels. There are some impacts due to high tailwater levels on connecting channels, for example, that may reduce the overall maximum capability of some plants. However, these negative impacts generally are not significant (69). Thermal interests will have ample depth of water for cooling purposes and water-borne shipment of fossil fuels. The implications of above average levels and flows are expected to be orders of magnitude less severe than those expected due to below average levels and flows and the study emphasis therefore will focus on the lower range. However, the impacts both positive and negative over a full range of probable water levels will be identified.

Most of the major hydropower generators were not on line during the 1930's when some of the lowest lake levels and connecting channel flows of record were experienced. While many projects were probably designed using data from that period, a recurrence of those same conditions is expected to reduce the projects' ability to meet contracted demands even though the interests are interconnected. Additionally, lower levels and flows than those experienced in the 1930's and the 1960's are likely to occur based upon the record. The probabilities of the 1930's, 1960's and other droughts have not been computed, although this should be accomplished in Phase II. If such conditions were to occur, the impact on any individual project would depend upon the magnitude and duration of the condition. The major implication is that committed hydropower generation would need to be replaced with alternative and more expensive thermal sources. However, the thermal interests also may be limited in their ability to generate or transmit power because they might be experiencing the effects of the same drought.

Low lake levels could reduce the ability of water-borne commerce to utilize ports, Great Lakes connecting channels and the St. Lawrence River and therefore reduce shipments of fossil fuel (Eberhardt, pers. comm.). The problem might be further compounded by the fact that other regions of the country, like the Mississippi, Ohio, and Missouri River Basins, likely would be experiencing the same drought conditions as, for example, they did in the 1930's. It is reasonable to expect that thermal interests would be hard-pressed to meet their own load commitments, let alone demands from the Great Lakes Basin.

This situation, in turn, would place an enormous burden upon interest sub-classes including: interconnected utility industries that can provide make-up power and energy; carriers that transport fossil fuels to pick up the slack due to reduced water-borne transport and natural resource producers that would need to increase production to meet the increased demands occasioned by the drought. It is expected that a large portion of the mid-west and eastern U.S. will be moderately to significantly affected. Portions of Canada would be similarly affected.

Meetings held with interests at an Electric Power Research Institute (EPRI) workshop in January 1989 (Appendix J), the New York Power Pool (NYPP) in November 1988, Ontario Hydro in March 1989 and Hydro-Quebec in April 1989 (Appendix K) and a Corps of Engineers Drought Conference held in October 1988 revealed that the aforementioned scenario is of concern.

Hydropower interests on the lakes and tributaries generated less power in 1988 than in the previous year due to lower Great Lakes levels and dry conditions on the tributaries. However, record breaking load demands were observed for several days in New York State and Ontario. These record load demands largely were due to increased use of air conditioners and fans. The New England Power Pool (NEPOOL) request for power from the NYPP was denied because of the need to meet load demands in New York State. The New England utilities experienced some problems in meeting demands during the summer of 1988 as a result. A survey of Massachusetts businesses referenced in (35) (sample size not clearly reported) found that power shortages in the summer of 1988 cost 100 companies a total of \$87 million dollars in lost business and productivity. Furthermore, a survey of 300 Massachusetts businesses conducted in June, 1988 by the Greater Boston Chamber of Commerce (referenced in (35)) showed that "93% think Massachusetts's economy will suffer a slowdown if power problems aren't alleviated".

Some of the thermal plants in New York State violated air and water discharge permit requirements during the summer of 1988, but received waivers to avoid plant shutdown. The St. Lawrence River at Montreal, Quebec, one of the most critical sections of the St. Lawrence Seaway, was within one foot of its alert depth, the depth below which navigation interests would begin to experience losses due to light loading and difficult navigation conditions. This was due to reduced outflows from Lake Ontario and more importantly, drought-induced low flows from the Ottawa River and other tributaries to the St. Lawrence River. In the meantime, the midwest, central and southern areas of the U.S. consisting mostly of the Missouri, Mississippi, Ohio, Cumberland, Tennesee and Illinois river basins, were experiencing moderate navigation problems and minor hydropower, water supply and other problems due to drought conditions.

The period 1987-1988 marked the first years of drought conditions of recent time. If a drought of this type were to continue in the entire Great Lakes basin beyond, say, two years, moderate to extreme impacts might be incurred not only by the electric utility industry but also by commercial navigation, recreational boating and other interests. The industry has begun to recognize that the isolated examples of impacts due to drought may become more widespread and have recommended specific research items be accomplished (Appendix J).

4.2 Review of Past Studies

Based on the actual experience of the twentieth century, episodes of water levels near to and/or exceeding the high and low points in the 100-year range of record have been a recurring problem. Moreover, changes in water levels can happen very rapidly. These two observations were seen to work during two previous major water level studies by the IJC. The first study was begun because of the 1962-64 period of extreme lows that reportedly had severe impacts on shipping.

From these lows, water levels rose by 1973 to what were then record all-time highs for some areas, prompting another study, this time restricted to Lake Erie. Subsequently, water levels receded towards more middle ground, only to again assault and exceed their all-time highs, culminating in the storms of 1985 and 1986, particularly, the December 1985 record-smashing blow and seiche on Lake Erie. Since that time, water levels have once again receded towards middle ground, this time very rapidly.

Past studies considered in this review analyse the impacts of water level fluctuations due to a number of causes. These studies examine the impact of structural works, diversions out of the Great Lakes, and lake level impact estimates due to climatic change. All examined reports are more or less related, using common water level baseline data, and essentially common economic data and models of the power interests.

However, important major assumptions underly the methodologies used for analysis. Impacts of water level fluctuations caused by various measures are derived from comparative analysis of static or given situations. The hydrologic base case in all studies is the period of record of Great Lakes average levels and flows. The impact case represents a new equilibrium set of average levels and flows resulting from the (analytically) instantaneous and complete adjustment of the base case to some specified changes, or the specified time-path of changes, being evaluated. In some cases, new minimum and maximum average levels were reported.

There is no consideration of the general environmental conditions accompanying the water level changes. This is important, because in real-time, (ie. the period during which the water level changes are being experienced), it matters what components are driving changes in net basin supplies. It is these components of change that make up the recognizable content, or information, of real "time".

The economic analyses are partial equilibrium evaluations using production cost models in a benefit-cost framework. The structural descriptions often are very detailed, however, there are no dynamics specified, only scalar growth. There is no consideration of real-time environment-economy interactions. Also, there is no similar time-dependent consideration of the economic condition of the interest, of connected interests, or of general economic conditions.

Therefore, it is the conclusion of this review that existing studies represent some progress in the evaluation of water fluctuation impacts. However, because they lack any consideration of context, they are lower-bound estimates of the sensitivity of the interest. This is particularly the case for extreme low levels, and their probable association with heat and drought, for which virtually no interest has a contingency plan. For example, Hyro-Quebec's capacity is almost totally hydraulic, yet there is limited planning for droughts or possible climatic change impacts.

The International Lake Erie Regulation (ILER) study (2) evaluation of measure 25N, showed the following changes in the mean levels of the Great Lakes: Superior, -.07 ft.; Michigan-Huron, -.22 ft.; Erie, -.59 ft.; Ontario, +.02 ft. Hydropower impacts amounted to an annual average loss of $2.5 million (1979). Unless otherwise indicated, all dollar amounts that follow are in 1979 terms.

This cost estimate has been criticized as involving assumptions that turned out to both overstate and understate the impacts. The choice of timing for the lows, in the future, discounted the costs to the interests. The real price escalations for oil assumed in the replacement energy valuations for New York power interests, and the relatively high peak capacity valuation factor for the same interest, have been criticized as overstatements. This escalation procedure is not now viewed as a reasonable way to go, as it introduces problems inherent in any forecasting method. On the other hand, suggestions that replacement costs should or could reflect current prices in the "wheeled" energy market assume that such replacement will always be available (infinite elasticity of supply). Interviews with the interest class found that most utilities assume that shortfalls can be made up by such purchases.

The reviewed reports show little or no collective sense of what will happen if everyone "heads for the door" at once, or of the limits to transmission capacity. This is another indicator of the fallacies inherent in thinking and planning only in average (expected value) terms, and in extrapolating actions that may be valid for individuals or small groups in times of relative plenty, to arbitrary size groups in times that may reflect shortage.

Examples of system problems were evident in New England and Quebec in 1988. New England was denied power from the NYPP in the summer of 1988 as a consequence of the need to meet load demands in New York State (Appendix K). As a result, New England utilities had problems meeting demand (35). There is no "on demand" interconnection solution to this problem. Also, Hydro-Quebec, normally an aggressive interconnected exporter, bought 800 mW of winter backup, partly because of lower than expected reservoir supplies (48, Appendix K). These problems are discussed in more detail below (Sections 4.3, 4.4).

The Wisconsin study (62) considered a number of scenarios of diversions out of the Great Lakes. A diversion of 10,000 cfs out of Lake Superior had the following impacts on mean lake levels: Superior, -.59 ft; Michigan-Huron, -.70 ft.; Erie, -.48 ft. Lake Ontario was not analysed. Based on the methods and data either derived from or acceptably consistent with the ILER study, this report estimated annual average losses to hydropower interests of $73.1 million.

This is compared to an estimate by the Diversions and Consumptive Uses study (63) of a 5,000 cfs diversion out of Superior. Mean lake level declines were: Superior, -.19 ft., Michigan-Huron, -.33 ft.; Erie, -.23 ft. Impacts were average annual losses of $40.2 million to hydropower interests. Economic methods and data were the same as in (2).

An example of a 30,000 cfs diversion, considered to be the upper limit of feasibility, resulted in the following impacts on mean lake levels (62): Superior, -.99 ft.; Michigan-Huron, -2.16 ft.; Erie, -1.48 ft. This resulted in average annual losses of $217.8 million to hydropower interests.

A recent study by Sanderson (16) provides a first-cut estimate of the impacts of climatic change scenarios on Great Lakes levels and hydropower. The combined climate change and consumptive use scenario results in the following mean lake level declines: Superior, -1.0 ft.; Michigan-Huron, -2.7 ft.; Erie, -2.3 ft.; Ontario, -2.3 ft. It was estimated that replacing lost hydropower production with thermal power could cost Ontario Hydro $65 million ($111 million 1984 Cdn) annually. However, it also was expected that warmer temperatures would reduce (winter) energy demand and that the savings associated with a decreased demand would more than offset the costs of lost hydropower. This type of analysis needs more work before a reasonable critique and debate can be undertaken. Further specific comment is beyond the scope of this work.

Crissman (14) presents an overview of potential impacts of climate induced declines in lake levels on the generation of electricity in New York State. Assuming that the average level of Lake Erie drops by 2.0 ft. in a smooth linear trend over the next 25 years Crissman calculates a "short run" (17 year planning horizon) average annual cost of $55 million (1988). By the end of the 25 year period, the so-called "long-run" average annual costs are on the order of $160 million (1988). Furthermore, presently planned industry efforts towards demand management may be offset and even exceeded by the impacts of the assumed change.

It is interesting to recall period of record possibilities of even greater declines for Erie, such as the two year decline of almost 3 ft. between 1987 and 1989. Under Sanderson's (16) scenario, Lake Erie's monthly minimum could be 5.31 ft. below the period of record mean level. Thus, it is entirely possible that Crissman's 25-year event could be compressed into 2 or 3 years, and the estimated $160 million cost per year in the distant future could turn into an almost $250 million cost per year in the near future. Add the fact that Great Lakes Basin precipitation for 1988 was slightly above average, and Lake Erie still declined, (due most likely to increased evaporation during the summer drought), further reveals the nature of interest sensitivity.

The Crissman study assumed that climatic change would increase average summer demand and decrease average winter demand in New York State, resulting in a zero net change in annual energy requirements. Possible impacts on peak summer and winter load requirements, and resultant implications were not explicitly considered.

The use of smoothed, averaged data from the past with linear, reversible models is an important focus point. The average per se is the one thing that is practically never experienced. In living systems (which is what the human economy must be) things can go beyond the point of no return.

What is of critical importance are the transient extrema, that may or may not be associated with the instability of a changing (non-stationary) mean or average environmental condition, like climate and related factors relevant to this discussion. The nature of the possible behaviour of the coupled environment-economy system, together with all the interests contained therein, will be qualitatively different at extrema. There are system reliability thresholds whose approach and exceedence can lead to irreversible events with truly non-linear aspects. Interest capacity to absorb economic and other impacts is limited.

When only two sets of average conditions are considered, like before climatic change or diversion, and after these events, the impacts on interests may appear relatively minor. However, the ability of the interest to "weather" the conditions that exist as the systems move between the two sets of average conditions, including possible transient extremes of relative short duration for which the interest or system lacks sufficient reserve or resistance, is another story.

In conclusion, available data and studies suggest that the electric power interest is sensitive and vulnerable to further periods of heat and drought and further declines in water levels and flows. These conditions are possible within the experience of the period of record. Climatic change related impacts may superimpose and severely worsen the situation, possibly synergistically. General economic system interdependence raises the possibility of far-reaching impacts in both space and time.

Work is required on real-time simulation of actual power systems and networks, using observations from the heat and drought and cold and wind experiences of recent years. Development and use of non-stationary stochastic and related chaos or surprise concepts, models, an understanding is an appropriate step.

4.3 Sensitivity of Primary Interests

The following is a list of impacts that could be incurred by the primary interests due to fluctuating levels and flows. This list was developed through meetings with the primary interests and therefore reflects their perceptions of the impacts of fluctuating levels and flows. Information provided in meetings with the primary interests has been supplemented or clarified, in some cases below, using industry and academic reports and articles.

a. Increased/decreased damages to electric plants due to storm induced levels and waves on top of high/low levels. Thermal interests contacted to date have indicated that plant flooding due to high water levels is not a large concern, although flooding could occur at some plants. For example, the subbasement and hotwells at Niagara Mohawk's Huntley 1 coal-fired plant have been flooded twice in the last ten years. The last flood resulted in a temporary shutdown of two units (Bob Thomas, pers. comm.). Flooding has occurred once at Ontario Hydro's Lambton coal-fired plant located on the St. Clair River (61). The flood resulted from an ice jam blocking river flow. Flooding has not been experienced at any other thermal plant in the Ontario Hydro system (61).

b. Reduced/increased hydropower output for firm energy commitments because of lower/higher levels and flows. Hydropower outputs, in general, can be increased with greater flows and/or head, although there is a threshold of extreme highs above which extra flow cannot be utilized due to physical limitations of equipment and/or hydraulic limitations. This excess flow is known as "spillage". Hydropower interests confirmed that impacts to firm energy are likely when levels and flows fall below long term monthly averages (Crissman, pers. comm.).

The primary interests expect that other units in their system or other systems will provide make-up power, at a higher cost, if water levels and flows fall below long term average (eg. 39).

The system would meet demands provided the decrease in hydropower capacity was not large and the demand did not increase significantly. However, during the drought conditions in the summer of 1988 the NYPP and Ontario Hydro experienced record breaking load demands for a short period of time. Ontario Hydro resorted to public appeals to reduce power demand. These appeals resulted in a demand reduction of approximately 200 mW (Appendix L). The New England Power Pool (NEPOOL) request for power from the NYPP was denied because of the need to meet demands in New York State. There is some concern in New England over the economic and social impacts should NEPOOL utilities be unable to meet current and future demands (35).

A Public Service Co. of Indiana coal-fired plant that withdraws cooling water from a river just outside the Great Lakes Basin had to temporarily shut down operation in the summer of 1988, in part, due to a lack of cooling water availability. The plant also suffered pump damage due to cavitation and siltation problems associated with the low water levels (40). This example emphasizes two points. First, thermal plants may experience problems of their own during drought conditions and therefore may not be able to pick up the reduction in hydropower capacity. Secondly, although systems may be linked by a transmission network, if drought conditions are widespread, it may not be possible to obtain power from other systems.

c. Increase/decrease in hydropower secondary energy due to high/low water levels which results in decreased/increased thermal fuel requirements. Secondary energy may be sold to other utilities in lieu of burning fossil fuels. Furthermore, utilization of available hydro generated power is economically beneficial for a utility and its customers. The cost of thermally generated make-up power can be several times greater than the cost of lost hydropower generation (8, 14).

The State of New York Public Service Commission has estimated that the state-wide average unit cost for replacement of Niagara Power Project and St. Lawrence-FDR Project generation by thermal generation is $30000/GWH (1987 dollars)(14). This estimate considered the fixed costs of capacity and transmission and the variable costs of fuel, operation and maintenance. As noted in (b), above, if widespread drought conditions are experienced, thermal plants may not be able to meet the increased demand associated with a large reduction in hydropower capacity. This could result in power shortages.

d. Reduced/increased head for hydropower generation due to high/low tailwater elevations for projects on connecting channels and high/low lake levels for projects along the lakes and tributaries. The power interests have indicated that the impacts from tailwater elevation fluctuations are minimal (69).

e. Flows below plant capacity can be advantageous with respect to maintenance, according to hydropower interests. Under these lower flows, generating units can be taken out of service and repaired, without giving up the benefits of less expensive hydropower. Maintenance advantages would be eliminated at the lower end of the observed flow range since unit maintenance can be done as marginal declines in flow occur relative to plant capacity.

f. Increased/decreased ability of thermal plants to obtain cooling water because of higher/lower levels and flows. Information about cooling water intakes, pumping requirements, and cooling water temperatures has been obtained for selected thermal power plants in New York State and Ontario (Appendix E). The water levels at which generating capacity would be affected by the inability to pump cooling water have been obtained directly for several plants (53, 68, Adamkoski, pers. comm., Fabian, pers. comm.). Information on the intake invert elevations was available for other plants (39, 52, 53, 55, 61). It was assumed for these latter plants that pumping problems would occur at water levels 6 ft. above invert elevation (ie. half the typical 12 ft. diameter for an intake pipe).

Water levels would have to drop approximately 4-26 ft. below the lowest observed levels before generating capacity in plants located on the lakes would be affected by the inability to pump cooling water. The exception to this range is Ontario Hydro's Lennox plant which could accommodate a 61 ft. drop in the Lake Ontario water level (55, 61). The projected monthly minimum levels due to climatic change typically are below the minimum observed levels (16). The difference between projected minimum levels (due to climatic change) and observed minimum levels are: Erie, 2 ft. below observed minimum; Ontario, 15 ft. below observed minimum; Michigan-Huron, 3 ft. below observed minimum; Superior, no difference. Plants drawing cooling water from the Great Lakes therefore may have some probability of experiencing difficulties in obtaining the water under projected worst case scenarios. However, under all conditions experienced historically, but excluding climatic change scenarios, the power plants should be able to obtain the volume of cooling water for full capacity operation.

Although generating capacity would not be affected, low lake levels would increase pumping costs (Vitale, pers. comm., Wright, pers. comm.). These costs have not been quantified to date. Furthermore, sediment transport may become more active around the cooling water intakes when water levels are lower. The amount of sand drawn into the intakes at Niagara Mohawk's Dunkirk plant increased during recent low levels on Lake Erie (Fabian, pers. comm.). Sand can increase the wear or damage the pumps.

Thermal plants drawing cooling water from connecting channels and tributaries may be more sensitive to low levels than plants drawing water from the lakes. As noted in (4.3c), a Public Service Co. of Indiana coal-fired plant situated on a river outside the Great Lakes Basin had to temporarily shut down operations in the summer of 1988, in part, due to a lack of cooling water. Niagara Mohawk's Huntley plant draws cooling water from the Niagara River. Low water levels combined with northeast winds twice produced a situation in 1964 (Mar. 16, Dec. 4) where there was a danger of not maintaining adequate pump suction submergence (68). There is a possibility that generating units would have to be shut down under such circumstances. Plants drawing cooling water from connecting channels and tributaries also could experience increased pumping costs and siltation problems due to low levels.

g. Reduced/increased generation capacity at thermal plants due to higher/lower cooling water temperatures resulting from low/high levels and flows. The interests generally agree that generating capacity could be impaired by higher cooling water temperatures. A reduction in generating capacity could result from two factors: i) a decrease in generating efficiency due to higher cooling water temperatures; and ii) legislative restrictions on effluent temperatures. These effluent restrictions would have a higher probability of being exceeded if intake temperatures are warmer. Plants may reduce load in order to meet effluent temperature regulations.

The magnitude of capacity reduction and the critical intake cooling water temperature above which capacity is reduced varies from plant to plant. Coal, oil and nuclear plants contacted in New York State and Ontario reported critical temperatures ranging from 70-80 degrees F (39, 52, 53, 55, 68, Adomkoski, pers. comm.). An estimate of the absolute magnitude of capacity reduction for a given increase above the critical temperature is not available from all thermal plants contacted. For example, the backpressure in the condensor at New York State Electric and Gas' Somerset coal-fired plant should never exceed 5 in. Hg. The backpressure is cooling water temperature and load dependent, and above a 77 degrees F critical temperature the backpressure exceeds 5 in. Hg. The generated load must be reduced to bring the pressure below 5 in. Hg if a cooling water temperature of 77 degrees F (or greater) is observed. However, no absolute load reduction estimate for the plant is available (54).

Output capacity at Niagara Mohawk's Oswego oil-fired plant would be reduced by approximately 3% at intake temperatures of 80 degrees F because of decreased generating efficiency (Adomkoski, pers. comm.). This critical temperature was observed at times during the summer of 1987. Degradation of output capacity would occur rapidly should intake temperatures exceed 80 degrees F, although the absolute magnitude of capacity reduction is unknown (Adomkoski, pers. comm.). Output capacity at Ontario Hydro's Nanticoke coal-fired plant is reduced by up to 3% at a critical temperature of 73.4 degrees F because of decreased generating efficiency (53; Wright, pers. comm.). This temperature is observed every summer during warm days. The reduction in output capacity would be greater than 3% at higher intake temperatures, but a quantitative relationship between temperature and capacity loss is not available (Wright, pers. comm.). As a rule of thumb, plants in the Ontario Hydro system will experience approximately a 10% loss in generating capacity for every 1.8 degree F increase in cooling water above 75 degrees F because of decreased generating efficiency (61).

Higher water temperatures could be expected with the lower water levels associated with drought or long term climatic warming. Changes in water temperature associated with modelled climatic change have not been considered in this IJC Reference (Eberhardt, pers. comm.), although this could be an important consideration for utilities. A lack of cooling water and the effect of cooling water temperature on power generation were identified as research concerns at a recent EPRI workshop on the 'Potential Effects of Climate Change on Electric Utilities' (Appendix J). Clearly, utility researchers and planners are beginning to feel that a complete evaluation of cooling water properties (availability and temperature impacts) is worthwhile.

h. Reduced/increased cost of transporting fossil fuels by water due to high/low water levels and flows. The effect of fluctuating water levels on the cost of transporting fossil fuels depends on the type of fuel, transportation methods and the sources of the fuel. Transportation methods and the sources of the fuel vary widely between plants and it is difficult to make generalizations about the impact of fluctuating levels on transportation costs. However, it has been suggested (16) that under various climatic warming scenarios, the annual navigation costs to the Canadian fleet to transport coal would increase by up to $60.2 million (1979 U.S. dollars) over the base of comparison (1970-1977, average) costs.

Canadian coal-fired plants could be sensitive to low lake levels because, for example, Ontario Hydro coal plants obtain coal via Great Lakes shipping (61). Clearly, the sensitivity of the Ontario Hydro plants depends on the distribution route (ie. across lake or through connecting channels). Contact with individual plants in the Ontario Hydro system has indicated that plant docking facilities are adequate to receive coal shipments during periods of low water levels. The limiting factor therefore might be transportation problems due to low water levels in connecting channels (eg. the Detroit River).

Coal-fired plants in the U.S. appear to obtain coal through a more diverse transportation network. For example, in New York State, Niagara Mohawk's Huntley plant obtains coal by rail (96%) and water (4%); Dunkirk by truck (13%) and rail (87%)(52). New York State Electric and Gas Corp.'s Somerset plant obtains coal solely by rail (39). Transport of coal by Great Lakes shipping represents 32.9% of coal distributed to the electric utility industry in the state of Michigan. Transport of coal by river represents 26.2%, 44.4% and 25.7% of the total amount of coal distributed to the electric utility industry in the states of Pennsylvania, Ohio and Indiana, respectively (Appendix D). A widespread drought clearly could impact the transportation of coal by water in the states of Pennsylvania, Ohio, Indiana and Michigan.

River transport of coal may not involve plants within the Great Lakes Basin. However, the thermal plants located on rivers adjacent to the Great Lakes Basin potentially would supply make-up power to primary interests within the basin. Low levels and flows in rivers adjacent to the Great Lakes Basin may adversely affect river transport of coal and hence reduce the power available for transfer. For example, a coal-fired plant owned by the Public Service Co. of Indiana and situated on a river just outside the Great Lakes Basin experienced difficulty obtaining coal in the summer of 1988 due to low water levels (40). The plant was forced to shut down for a short period of time due to the inability to obtain coal and cooling water.

Much of the residual fuel oil used by oil-fired plants in north eastern North America is obtained from foreign and overseas sources (23). The oil typically is delivered to a central depot and from there is distributed to the individual plants by various methods. Oil for the Ontario Hydro Lennox plant, for example, is obtained from North Africa and Venezuala via rail from a depot in Montreal (Haskim, pers. comm.). Approximately 30% of the oil for Niagara Mohawk's Oswego plant is obtained by water-borne transport along the St. Lawrence River. It was suggested that train deliveries to the plant would have to supplement barge deliveries in the event of low water levels (52). This was not perceived as a problem because trains currently make all deliveries when the seaway closes for the winter. Nonetheless, low St. Lawrence River levels could have an effect on the receipt of fuel oils at some plants.

i. Reduced/increased effects of thermal discharges on receiving water temperature and dissolved oxygen due to high/low water levels and flows. Violations of Nuclear Regulatory Commission (NRC) guidelines on the temperature of cooling water discharged to a receiving body occurred at two plants in New York State during 1988 (source: NYPP). Waivers were obtained and the violations did not cause plant shutdown. Some information on the frequency of discharge temperature exceedences within the Great Lakes Basin has been obtained but a more detailed investigation should be carried out in Phase II.

Ontario Hydro indicated that three plants have had problems meeting temperature regulations in the past two years (61). The plants and associated frequencies are as follows: Pickering, 1987 - 43 exceedences, 1988 - 19 exceedences; Lambton, 1987 -5 exceedences, 1988 - 23 exceedences; Bruce, 1988 -14 exceedences. Increased dependence on thermal electric power due to low water levels could increase the frequency and magnitude of temperature violations. Increases in receiving water body temperatures of less than 15 degrees F, due to cooling water discharge, are perceived by some groups to have a positive impact on aquatic biota (32).

j. Increased emissions of NOx, COx, SOx, selenium due to increases in thermal power production associated with decreases in hydropower generation during low levels and flows. The Ontario Hydro system used 5 million tonnes more coal in 1988 than had been forecast (60). A combination of higher demand and decreased hydropower output necessitated the additional coal usage. Despite this increased use of coal, acid gas emissions for the entire Ontario Hydro system remained within the annual regulation limits. Three fossil fuel stations in the Ontario Hydro system did, however, exceed hourly sulphur dioxide limits in the past two years (61): Lakeview, 1987 - 7 exceedences, 1988 -7 exceedences; Nanticoke, 1987 -2 exceedences, 1988 -2 exceedences; Lambton, 1987 - 3 exceedences. Ontario Hydro is committed to reduce acid gas emissions by 50-60% between 1989-1994 (60). Emissions will be reduced through a combination of various options, including, reduced coal generation, use of coal with lower sulphur content, installation of emission control equipment, and use of lower emission technology (eg. integrated gasification combined cycle and fluidized bed technologies)(60). None of Ontario Hydro's nuclear stations have exceeded atmospheric discharge regulations. Various plants in New York State have reported periodic exceedences of opacity and soot regulations (Thomas, pers. comm., 52), although absolute frequencies have not been obtained.

k. Increased/decreased problems of fly ash disposal associated with increased/decreased thermal generation. The electric utility industry currently disposes of ash in two ways, marketing and landfill (8, 33). Ash can be marketed as a concrete additive, for the production of cinder blocks, as a liquid waste stabilizer in waste management, and as an anti-skid agent for icy roads. Research also is being carried out to evaluate the economic feasibility of extracting and selling metals contained within the fly ash (33).

Proposed landfills in the United States and Canada must meet environmental guidelines determined by the state/provincial governments. It is emphasized (8, 33) that landfill sites can be reverted to an undeveloped condition and blend with natural surroundings or be used as a location for light industry.

l. Increase in cost and responsibility for water contamination monitoring and waste disposal site construction and monitoring due to a (possible) increase in nuclear generated electric capacity.

m. Increase in consumptive use of water due to increased thermal production during drought conditions. This could lead to even lower levels and flows and possible conflict with other water users particularly on tributary streams (source: NYPP).

Consumptive use of water primarily is the result of evaporative losses in the cooling process and therefore is a function of the type of cooling system employed at a particular plant. Ten of the fifteen thermal plants for which data were obtained experience some loss. The reported evaporative losses range between 3.5-92 cfs (52, 61). It may be possible that some plants reporting no loss actually experience a loss near the low end of the reported range. Nuclear plants often experience the largest evaporative losses (52, 61), probably because of higher installed capacities and the type of cooling system employed.

Consumptive losses can be estimated for plants that might experience such losses but for which no data are available. This was done using the procedure outlined in (1) for a theoretical plant with output capacity and heat rates similar to the Huntley coal-fired plant in New York State. Observed heat rates were available for the Huntley plant (6) and therefore did not have to be estimated as is done in (1). Consumptive use for the theoretical plant is estimated to be 5.6 cfs per day. This estimate seems reasonable given the reported evaporation losses (61).

The consumptive use of Great Lakes water by all Ontario Hydro plants is approximately 431 cfs (61) and by U.S. thermal interests was approximately 830-1700 cfs in 1985 (67). The U.S. and Ontario Hydro values would account for most of the thermal electric consumptive use of Great Lakes water. In total, this consumptive use represents approximately 0.2-1.0% of the long term average outflow from Lake Erie. It appears that consumptive use would not be a significant loss for any of the Great Lakes or for large tributaries (eg. Hudson River, New York State) used as sources of cooling water.

n. Reduced/increased cost of dredging channels and harbors due to high/low water levels and flows. Dredging facilitates transport of fossil fuels during low levels and flows.

o. Advancement/retardation of freeze up and break up dates due to a change in water energy budget resulting from high/low levels and flows.

p. Potential increase in public relations activities and regulatory agency interactions to explain and achieve rate increases under low flow scenarios that require replacing hydropower with other sources.

q. Increased use of more expensive sources of electricity, due to reductions in hydropower generation, may increase pressure on the industry and its customers to implement demand management programs to reduce peak demands. This may or may not be a benefit, depending on the costs of such programs relative to those of supplying the additional energy.

4.4 Sensitivity of Sub-class Interests

The implications of fluctuating levels and flows for the sub-class interests have been determined through meetings and discussions with sub-class and primary interests and also from the literature. The following is a list of perceived impacts:

a. Increased/decreased requirements of interconnected utilities to provide/not provide make-up power and energy due to effects arising from low/high levels. Interconnection serves two purposes. First, it allows energy to be wheeled on a short term basis (ie. several minutes to several days). Short term energy would be imported by a utility during emergency situations (eg. blackouts) or when secondary energy was available from another utility at economical rates. A utility cannot depend on short term wheeling to make up for a lack of capacity over an extended period of time (eg. months). Second, interconnection allows long term contracts for power transfer to be arranged.

It is possible, however, that interconnected utilities may not be able to generate power themselves under a low flow scenario and power would not be available for transfer. Furthermore, interconnection limitations may exist. For example, transfer from ECAR to NPCC is limited to 2,000 mW in the summer (Appendix F). The total winter capacity for NPCC is 113,628 mW (34) and capacity would be similar in the summer. ECAR therefore is only capable of making up approximately 1.8% of the NPCC requirements. Blackouts or brownouts may occur if a utility depends too heavily on importing energy through interconnection.

b. Increased/decreased need for other means of transporting fossil fuels due to decreased/increased water-borne transportation resulting from low/high levels. As noted above and in Appendix D, water-borne transportation constitutes a significant proportion of total coal transport for the states of Pennsylvania, Ohio, Indiana and Michigan and for the province of Ontario. Rail and truck transport therefore would increase in these states/province and this would be of benefit to rail and truck transport interests, to an extent. However, there may not be enough rail cars, for example, to make up for complete elimination of coal transport by water should this scenario result due to extreme low levels and flows. Accordingly, coal-fired plants may have difficulty obtaining raw materials, and firm power commitments therefore might not be met.

A large amount of oil used by North American utilities is imported from overseas sources and stored in central depots, as noted in 4.3h. Low St. Lawrence Seaway levels could adversely affect distribution of overseas oil to depots such as Montreal. Data indicate that individual plants may obtain fuel oil by truck, rail or pipeline from a central depot (Appendix L), and carriers servicing oil-fired plants could benefit from increased oil demand (provided the oil can reach the depot).

It has not been determined at this point how fluctuating water levels might indirectly impact the distribution of natural gas or uranium.

c. Increase/decrease in consumer concern over higher/lower electricity costs resulting from a greater/lesser dependence on thermal power generation and power imports. Consumers could adapt to the negative impact of higher electricity rates through demand side management practices such as improved efficiency of appliances/motors, improved insulation in homes, off-hour electric consumption, reduced demand.

d. Consumers could experience selected forced power outages during peak demand periods under a low flow/drought scenario. Outages could result from a combination of increased demand, peaking capacity constraints and maintenance of existing or planned generation facilities. Unpredicted outages could result in significant adverse consequences for consumers.

Ontario Hydro and the Power Systems Research Group (PSRG) at the University of Saskatchewan have surveyed customers in different parts of Canada to determine costs incurred due to unpredicted outages of different durations. In Ontario, the estimated costs (1980 Cdn dollars) of an unpredicted 20 minute blackout ranged from $0.04/kW for residential customers to $2.46/kW for large industrial users to $174.70/kW for large farms (56). Estimated costs increased with increasing outage duration. Many respondents to the survey indicated that cost savings were possible if Ontario Hydro gave adequate warning and information about the extent of the outages (56). It was indicated that warning would be most useful if given at least 16 hours before the outage.

The PSRG surveyed customers in areas throughout Canada and obtained comparable cost estimates to those of Ontario Hydro for a 20 minute interruption (57). Comparable results also were obtained for a 4 hour interruption, except for the residential sector. The cost estimate to the residential sector for a 4 hour outage was $0.07/kW in the Ontario Hydro report (56) and $3.16/kW in the PSRG report (57). It was suggested (57) that the Ontario Hydro estimates were lower because of differences in the interruption frequency scenarios and the nonlinear variation of costs associated with interruption frequency.

As noted in Section 4.1, a survey of Massachusetts businesses (referenced in (35)) found that power shortages in the summer of 1988 cost 100 companies a total of $87 million in lost business and productivity. A recent (March 13, 1989) province-wide blackout in Quebec is estimated to have cost several large companies millions of dollars. For example, it was estimated that the General Motors assembly plant near Montreal incurred costs of approximately $6.6 million in lost productivity, and Sidbec-Dosco, a Quebec-owned steel company estimated losses to be $0.5-1.5 million (59).

e. Reduction of existing and future electrical generation capacity may impact utilities ability to raise capital in the financial markets.

f. Outstanding bonds, stocks, and other debt instruments issued by the utilities, and held by investors, may be adversely affected by significant reduction in energy production.

g. Additional installed capacity, if warranted to meet existing loads or reserve requirements, may require significant capital intensive investments. Bond ratings and thus interest on debt issues could be affected by regulatory operational plans significantly affecting water levels and flows.

h. Fluctuating water levels may impact government policy regarding water conservation, power and energy pricing, nuclear generation and plant efficiency. For example, it was suggested at a recent EPRI workshop that possible legislative responses to climatic warming might include forcing utilities to implement conservation programs, supporting research and development of renewable energy sources, development of least-cost energy plans (ie. least-cost from a societal perspective, which for utilities could mean paying for the cost of pollution production associated with power generation), supporting research and development of best available emissions control technology, and supporting research and development of safer nuclear production (41). There appears to be growing political concern over the impact of electric power generation on the environment, particularly with respect to global climatic warming, as evidenced by several acts recently introduced to the U.S. congress (eg. The Global Environmental Protection Act of 1988; The National Energy Policy Act of 1988; The Global Warming Prevention Act of 1988; The National Global Change Research and Policy Act of 1988).

i. State/provincial and Federal agencies may review existing transmission linkages if new sources are introduced to ensure network sufficiency.

j. Public service commissions and other state regulatory agencies may review existing operational patterns and rate structures of energy producers to ensure an adequate rate of return to capital.

k. Increased/decreased concern of public interest and environmental groups over adverse environmental consequences associated with increased/decreased thermal electric generation. The Ohio Coastal Resource Management Task Force (28, 31) was concerned about pollutants associated with fly ash and the possible storage of low level radioactive waste from the Besse-Davis nuclear plant on the Lake Erie floodplain.

Great Lakes United (Ahl, pers. comm.) was concerned that an increase in thermal electric generation could result in: i) a possible increase in fly ash emission to the atmosphere, along with increased emissions of greenhouse gases, heavy metals and organic pollutants; and ii) increased land requirements for fly ash disposal. The problem of atmospheric emissions has been discussed above (eg. 4.3j; 4.4h). It also was suggested (Ahl, pers. comm.) that increased coal consumption would require additional stockpiling at the generating plants, potentially increasing acidic runoff from coal piles. Runoff pH from coal piles may range between 1.4 and 5.8 (58). In addition, polynuclear aromatic hydrocarbons, which may be carcinogenic, have been observed in coal pile leachate (58).

Available information indicates that coal stockpiles typically are contained within a holding area lined with some type of relatively impervious material such as clay or polyethelene sheeting (32, 53, 54, Fabian, pers. comm.). These liners limit interaction with groundwater. Coal pile runoff and leachate are collected and treated at all plants that were contacted, although information on the methods of treatment is incomplete. However, at Niagara Mohawk's Dunkirk plant, treatment includes filtration, polymer and lye additions, pH balancing and metal separation (Fabian, pers. comm.).

Between 1973 and 1984, the electric utility industry in the U.S. had a larger share of pollution (air and water) abatement new plant and equipment expenditures than any other single industry, but this share has declined since 1984 (43). This declining share has been attributed to several factors including: a decrease in added generating capacity in recent years caused by slow demand growth, past cost overruns and regulatory constraints (43). It is suggested (43) that rather than adding capacity, U.S. utilities are: i) prolonging the lives of existing plants because these plants are not required to comply with stricter emission standards for newly constructed plants; or ii) purchasing power from other utilities (eg. Hydro-Quebec) as an alternative to construction.

l. Increased/decreased concern of public interest and environmental groups over the temperature of cooling water discharged to a receiving water body and the effects on aquatic biota. Ahl (pers. comm.) suggested that higher water temperatures near cooling water discharges could result from low lake levels and benefit warm water fishes such as perch and walleye. However, higher water temperatures would have an adverse effect on cold water fishes such as trout.

m. Increase in the level of research and development of new technology to reduce emission of pollutants to the atmosphere and to safely store nuclear waste.

n. Energy dislocations may require more frequent use of hydropower peaking plants located on tributaries. The effect may be significant drawdown of sub-basin water levels. This may affect operation of canals, such as the New York State Barge Canal, water levels on rivers, and extensive recreation activities on inland systems.

4.5 Summary of Interest and Sub-class Interest Sensitivity

Sections 4.3 and 4.4 represent sensitivities of primary and sub-class interests as identified by the work group members and the interests themselves. The perceptions of the interests regarding the consequences of fluctuating levels therefore are inherently contained within these sections (also as evidenced by the references). Salient points of information regarding these perceived sensitivities also were included by the work group members. This section summarizes the critical areas of sensitivity as identified by the work group.

The negative impacts of high water levels are perceived by the primary interests and by the work group to be of relatively minor significance. Information collected from the utilities and the NYPP show that docking facilities and structures are constructed to limit flooding/high water problems. Although overall maximum generating capacity may be affected due to high tailwater levels at some plants, this does not appear to be a significant problem. High water levels generally are beneficial to utilities and their customers because of greater potential hydropower generation, lower temperature cooling water and greater depths for transportation of fossil fuels.

Concern about low water levels falls into four broad categories: a. costs of power generation; b. power shortages; c. environment; d. planning.

4.5.1 Costs of Power Generation

Increased dependence on thermal power due to low water levels and a reduction in hydropower capacity will increase the cost of electricity (eg. 14, 8). The absolute magnitude and rate of cost increase cannot be determined at this point. Thermal power currently is more costly to produce and under a low flow scenario, the cost of thermal power production could be further increased. The cost increases could result from the greater transportation costs for raw materials (eg. 61) and, to a lesser extent, greater costs of pumping cooling water (increases in pumping costs were noted by Wright, pers. comm. and the NYPP). These cost increases could be evaluated quantitatively in Phase II of the study.

4.5.2 Power Availability

The ability of thermal power plants to make up demands not met by hydropower due to low water levels could be affected by:

1) higher intake cooling water temperatures
2) inability to obtain cooling water
3) restricted ability to obtain raw materials
4) unforeseen increases in demand

Generating capacity may be reduced by higher cooling water temperatures. The magnitude of capacity reduction and the critical temperature above which reductions occur, varies from plant to plant. Reductions in capacity of up to 3% have been observed at some plants and as a general rule of thumb, plants in the Ontario Hydro system would experience a loss in generating capacity of approximately 10% for every 1.8 degree F increase above an intake temperature of 75 degrees F. Reductions in generating capacity therefore would be greater than 3% at higher water temperatures. Several interests have noted that warmer cooling water could be a concern. The work group concurs, and it is suggested that the possible impacts of warmer cooling water should be evaluated more fully. Water temperatures associated with climatic change are not being investigated (Eberhardt, pers. comm.), but this may be useful information to obtain in Phase II.

Power plants drawing cooling water from the Great Lakes are less likely to have problems than those located on smaller tributaries. As noted in Section 4.3, an isolated case of cooling water problems forcing the shutdown of a thermal plant was reported in Indiana last summer. Under an extended drought scenario, such occurrences could become more widespread.

Lower water levels may restrict water transport of fuel materials to some thermal plants, although most of the problems would probably be associated with trips through connecting channels and up tributaries (40). As noted from Appendices C and D, the states of Pennsylvania, Ohio, Indiana and Michigan and the province of Ontario could experience the greatest negative impacts with respect to the inability to ship coal by water. Simple multiplication of the percentage of water-transported coal (Appendix D) by the state percentage of coal-fired power (Appendix C) shows that for Ohio, Pennsylvania, Indiana and Michigan 38%, 14%, 24% and 21% of the total state power capacity, respectively, could be impacted in some way. These numbers are worst case scenarios and these results do not mean, for example, that Ohio would experience a 38% reduction in capacity. The numbers do suggest, however, that a maximum of 38% of Ohio electric power could be impacted in some way (eg. higher costs or generation reductions).

The high air temperatures experienced during the summer drought of 1988 resulted in record load demands in New York State and Ontario (Appendix K). These record demands largely were associated with increased use of air conditioners and fans. A combination of unforeseen increases in demand (as experienced last summer) and reduced generation capacity, due to lower flows and regular unit maintenance, could result in power shortages. Ontario Hydro, for example, issued public appeals in the summer of 1988 to reduce demand in order to decrease the possibility of shortages. Phase II of the study should pursue the question of utility response to (possible) higher demands and lower generating capacity. The utilities have started to evaluate such conditions as evidenced by (21).

Finally, it was found that utilities typically assumed that short term power shortfalls would be made up by purchases from other systems. However, if the drought was widespread it is likely that power systems would not have excess power to sell each other (eg. 35, 48). Furthermore, interconnected utilities likely would not be able to transmit the required power because of interconnection limitations. The NYPP is interested in exploring the implications of low flow scenarios on power demand, power generation and power transfer.

4.5.3 Pollution

The potential for increases in at least 4 types of pollution exists should low water levels result in an increased reliance on thermal power:

1) atmospheric - (greenhouse/acid gases, and possibly nuclear fallout (42, 49))
2) thermal - increased water temperatures due to cooling water discharge
3) water chemistry - including possible effects from coal pile runoff and radioactive escape from nuclear plants
4) soil - due to atmospheric and groundwater emissions and fly ash disposal

The electric power industry has addressed all of these concerns as noted in Sections 4.3 and 4.4 (eg. 32, 33, 39, 42, 45, 53, 54, 61). However, the question remains whether the industry is taking a lead role in pursuing pollution control. Clearly, one of the problems is that there does not appear to be agreement in the industry or in the scientific community as to the severity of environmental problems related to thermal power activity (42, 46, 47).

This work group agrees that pollution is a global concern and pollutant contributions by thermal power plants likely would increase given low water levels because of the increased need for thermal power production. Furthermore, it appears likely that the industry would petition to have restrictions on atmospheric emissions and thermal discharges waived in order to ensure thermal production remained as high as possible in attempts to avoid shortfalls. In some respects, the industry is caught in a difficult situation. The public demands reliable electric energy, but at the same time is concerned about the environment. Extensive pollution control is costly and utilities seem reluctant to make such investments, citing the unwillingness of the public to pay higher rates to help defray costs. However, for long term environmental "good health" it may be necessary to introduce measures such as higher rates or tax incentives to pay for best pollution technology. This approach apparently is being pursued by Ontario Hydro (60).

4.5.4 Planning

The most important and encompassing determinant of the sensitivity of interests to water fluctuations is the planning approach and context. This includes quite a number of factors, with the following being viewed as the most important for present purposes (34, 19, 14, 10).

1) The scale, complexity, diversity, interconnectedness (and interdependence), age profile, and operating margins of the generation and transmission networks.
2) Approach to viewing demand growth, scale, and volatility; capacity growth and scale, and risk-taking.
3) Views on the importance of the atmospheric forcing variables that drive water fluctuations, including drought and heat.
4) Views and approaches to environmental stresses like acid rain, global climatic warming and stratospheric ozone depletion.
5) The extent of self-regulation, adaptive capabilities, and contingency plans to respond to prolonged environmental stress and associated positive feedbacks.
6) Philosophy and approach to conservation and demand management as corporate goals, with emphasis on the marketing of power engineering expertise directed towards turning generating capacity into free energy, as opposed to just marketing power.
7) Assumptions about feasibility and sustainability of growth scenarios, and system resilience to errors.

From meetings held with the interests and from interest planning documents and reliability assessments, some observations on these factors can be made. Planning contexts are dominated by growth scenarios that are increasingly volatile, and imprecise or uncertain, with no evident concern for physical feasibility or sustainability. These scenarios are based on smoothed or averaged historical data used to estimate simple models that are linear and reversible. The models are then extrapolated without consideration of qualitative changes (eg. changes in scale and density) in the socio-environmental system and the nature of these changes in relation to space and time. Weather is assumed to be average. However, prolonged heat and/or drought may lead to increased use of air conditioning as well as other demand increases. A reduction in hydropower, and perhaps thermal power, also may be experienced. Finally, increased environmental problems of air pollution and water pollution may occur. These factors may interact in positive feedback under the prolonged drought scenario, but such interactions are not considered in the planning process (7, 34).

The physical scale, complexity, interconnection and interdependence of the North American electric system is now very substantial, and it continues toward further growth in all these factors (34). Problems were noted with the possible adequacy of supply and related factors, indicating feasibility issues in conflict with a philosophy of meeting all demand regardless of scale (34). A sometimes delicate balance between supply capability and peak demand also was noted. Areas adjacent to the Great Lakes were included as being at risk (34).

In addition, operating margins are being shaved as a variety of influences are allowing and forcing system operations towards the edge of their technical limits (34). Moreover, these influences often act in positive feedback. As a consequence of the approach to these limits, and since all the system factors are interlinked, the resultant rigidity and lack of flexibility spreads through the system (34).

The system is slow to make changes in its operating environment, particularly with respect to environmental quality issues like acid rain and COx contributions to global warming. Society's regulatory mechanisms often are viewed as obstacles to growth (34) and the system therefore tends to resist the implementation of such regulatory mechanisms. This view of ecological system dynamics only serves to worsen the already emerging vulnerability of the system to other changes and stresses (34, 7).

Resistance to change also exists in the areas of conservation and demand management. The U.S. reliance on not-yet implemented Federal appliance standards, and still tentative commercial and residential building standards, with no initiatives at the industrial level, is not much of a conservation program. For example, the NYPP identified a possible 1000-2500 mW reduction in demand by 2005 due to the proposed efficiency standards. An additional summer peak demand reduction of 1370 mW is expected by 2004, due to commercial and residential demand management. These reductions compare to a present maximum installed capacity in New York State of about 32000 mW, and a projected maximum installed capacity of about 36000 mW in 2004 (6).

In Canada, conservation efforts are not aggressive, but biased towards incentive driven, long lead-time, marketing based programs, paid for by the utility. Specific identified demand management aims of Hydro-Quebec show a possible 2000 mW of peak load shifting due to dual-energy heating by 1998, and a possible 2000 mW peak demand reduction due to an interruptible power program over the same period. These programs are not for conservation purposes, but for peak load management. The 4000 mW compare to a total installed capacity of about 25000 mW, and planned expansion of 18000 mW (with a possible further 12000 mW under better economic conditions). Demand management programs (eg. R2000 homes, variable speed industrial motors) were discussed at the Hydro-Quebec meeting (Appendix K), but the magnitude of power reductions associated with these programs was not disclosed.

Ontario Hydro has suggested that demand reductions of 1000-4000 mW may be possible by the year 2000 due to increased efficiency in use (7). This compares with an existing and committed total capacity of about 32400 mW (about 26000 mW reliable peak) by 1993. Additional power needs by the year 2000 may range between 2600-9300 mW and by 2005 between 5500-15900 mW.

Conservation and demand management efforts in both countries lack aggressiveness despite continued utility warnings about impending supply-demand gaps, and the large literature on the waste of energy, including electricity (eg. 64, 65, 66). This situation reinforces the observation that planning is biased towards growth despite all the real financial and environmental risks that such a course entails. There is no deliberate strategic plan to make things happen through "anticipate and prevent", except perhaps lobbying for relief from regulations. Moreover, there has been little evidence of carefully thought out drought contingency plans; and until recently, little account taken of greenhouse gas emissions and their links to climatic change and acid rain (34, 7, 10, Appendix J, 50).

In overview, the planning approach and context, and operational imperatives of the interest create a system that is sensitive to changes that push the variables of the system to their extreme operating limits (34). This fact, combined with the tendencies of the underlying habits of thought, institutions, and regulations, will make the system more and more prone to serious or catastrophic breakdown (34). In considering this, it is important to look at the larger system level. Events that can be predicted at the larger level may be relatively unpredictable from study of only a small subsystem (34, 19).

The real phenomena that should be planned for are not experienced as smoothed averages of past history. Also, while system responses to stress appear to have many thresholds up to which linearity is seen, once thresholds are exceeded, the effects may be non-linear, or irreversible, or cumulative, or lagged, or compounding, or even synergistic. Moreover, system crashes or catastrophes are by definition non-linear, with effects that may be any or all of the foregoing. Avoidance of such events is a matter of informed prudence. It would be unfortunate, if despite understanding sufficient to foresee the harmful event, in actuality it is not foreseen (19).

5. IMPACTS OF MEASURES ON INTERESTS

A measure is any action, initiated by a level(s) of government to address the issue of lake level fluctuations, including the decision to do nothing. A full definition of measures can be found under the Glossary of Terms in the IJC Phase I Main Report. Measures have been classified into six types and Section 5 outlines the possible impacts of example measures from each of the six classes. These example measures are not an exhaustive list of possible measures. A more detailed evaluation of the example measures and other possible measures will be done in Phase II of the Reference.

5.1 Type I-Public/Private Investment in Control and Diversion Works

5.1.1 Measure I.1-Combine Full Regulation of Lake Erie Outflows Via a 50N Scheme

This measure includes increasing the outflow capacity of the Niagara River at all lake stages, with a maximum at high lake stages of 50,000 cfs, using a structure across the full width of the Niagara River near Lake Erie combined with regulation plans. Such regulation plans could be patterned after the one presently in use for Lake Ontario where the levels are regulated as nearly as possible to the long term monthly averages. Consideration also could be given to variations around those averages, say one-half foot above or below the monthly averages. Variable release rates within the day either alone or in combination with increased and/or decreased storage utilization in the Grass Island Pool just upstream from Niagara Falls could be considered. The usefulness of extending the existing Grass Island Pool Control structure also could be investigated either in combination with this measure or by itself. The extension of the control structure will be recommended as a measure to be considered in this study. Another measure would be modification of the 1950 treaty between Canada and the U.S. that prescribes flow requirements over Niagara Falls.

Any regulation plan for Lake Erie would have to recognize that variations about the long term monthly means are inevitable. To determine the extent of these variations, given a control structure design, requires modelling. Even if control structure capabilities would permit perfect regulation of Lake Erie, a tremendous stress subsequently could be placed on the Lake Ontario regulation because water supplies can vary so drastically. Most regulation plans recognize downstream interests and attempt to balance them with upstream interests. This means that during high inflows, both water levels and outflows rise. The converse also holds.

The primary hydropower and thermal interests feel that this measure could reduce the range of Lake Erie levels and could reduce negative impacts, depending on the regulation scheme.

Benefits to power production from a control structure at the Lake Erie outlet would have to be weighed against the costs (economic, social, political, environmental) of the structure before hydropower interests would be eager to be sponsors. The electric power work group concurs in the above assessment.

Government policy for regulation of the shoreline and development of shoreline management plans also would be affected by this measure.

This measure may not be sufficient to offset all of the negative effects of low water levels associated with a severe and prolonged drought. Nonstructural measures such as voltage reductions, public appeals and even scheduled blackouts might be needed to reduce peak demands.

5.1.2 Measure I.2-Interbasin Diversions

Measures of this type, like the Chicago diversion, would have negative effects on the hydropower primary interests if the diversions bypass the hydropower projects. All of the hydropower projects on the connecting channels utilize essentially 100% of the flow available for power. Any reduction in flow will reduce their ability to generate both firm and secondary energy, depending upon the level and flow conditions (high/low) in the channels at the time. Diversions into the Great Lakes such as the Long Lac-Ogoki have had a positive impact on most interests. Additional such diversions would increase positive impacts.

5.2 Type II-Public Investment to Direct Land and Water Use to Adapt to Shore Fluctuating Levels

5.2.1 Measure II.1-Barrier Island Construction

Power plants that are subject to flooding due to set-up and waves on top of high lake levels are expected to be the only interests affected by barrier islands constructed in the lakes, just offshore from damageable property. However, since barrier islands would be a local measure and power plants are normally removed from areas of concern to other interests, it is unlikely that any benefits would accrue to the power industry from such measures. Barrier island construction to protect individual power plants might not be cost effective unless water levels were to rise above maximum historical levels. Barrier island construction to protect other interests might benefit the power industry if it allowed for water levels to remain higher relative to the "do nothing" condition.

5.2.2 Measure II.2-Navigation and Access Channel Dredging/Deepening

This measure would reduce impacts to thermal primary interests associated with low levels and flows. Ships transporting fuels will have easier access to harbors and other mooring points. Deepening uncontrolled navigation channels between lakes would have a long term impact of lowering the upstream lake levels. Both positive and negative impacts would result.

5.2.3 Measure II.3-Structural Floodproofing

This measure would reduce flood damage potential to electric plants that are subject to flooding from wind set-up and waves on top of high levels. This measure might be more cost effective for protecting individual power plants from high water damage than barrier islands. Floodproofing measures to protect other interests might benefit the power industry, if they allowed for water levels to remain higher relative to the "do nothing" condition. This would only apply to those existing and future projects that utilize the lake levels directly for head to generate electricity.

5.3 Type III-Direct Public Regulation of Land and Water Use

5.3.1 Measure III.1-Mandatory Structural Setback Zoning

This measure would benefit existing electric plants in the floodplains and future electric plant construction. If implemented for all structures and combined with regulation to allow water levels to remain higher than under the "do nothing" scenario, significant benefits would accrue to existing and future hydropower plants that utilize the lake levels directly for head to generate electricity. This also would benefit utilities and their customers by reducing the need for more expensive thermal power. This measure can go hand and hand with other types of measures.

5.3.2 Measure III.2-Subsidized Structure Relocation

This measure would benefit electric plants in the floodplains. If implemented for all structures and combined with regulation to allow water levels to remain higher than under the "do nothing" scenario, significant benefits would accrue to existing and future hydropower plants. This measure can go hand in hand with other types of measures.

5.4 Type IV-Public Programs to Indirectly Influence Land and Water or the Effects of Fluctuating Levels

5.4.1 Measure IV.1-Interest Rate Subsidy Loan

Implementation of this measure is not expected to affect the electrical generating industry.

5.4.2 Measure IV.2-Real Estate Disclosure

Implementation of this measure is not expected to affect the electrical generating industry.

5.4.3 Measure IV.3-Tax Abatement Program

Implementation of this measure is not expected to affect the electrical generating industry.

5.5 Type V-Emergency Response Capacity

5.5.1 Measure V.1-Emergency Sand Bag and Dyking Assistance

Implementation of this measure is not expected to affect the electrical generating industry.

5.5.2 Measure V.2-Storm Forecasting

Implementation of this measure in general is not expected to affect the electrical generating industry. However, in the absence of Lake Erie regulation, improved storm forecasting techniques would provide some benefit to hydropower interests on the Niagara River, and possibly other locations. Accurate forecasts of storm induced water level and river flow changes would allow for more efficient utilization of the water available for hydropower generation. The incremental benefits of improved forecasting would be small compared to those measures that incorporate lake regulation.

6. CRITERIA

6.1 Discussion of Criteria Suggested by Interests to Evaluate Measures

6.1.1 Hydropower Interests

Hydroelectric energy generated from the waters of the Great Lakes is the least expensive, most environmentally acceptable and reliable of all the forms of electricity generation in the basin. As a result, the electric utility industries in New York and Ontario have developed regional operating strategies that maximize the use of hydropower and minimize the use of other types of generation given the demand that must be met. Therefore, the criteria selected to assess measures should be related to the utilities' operating objectives and goals.

The operating strategies of the industry with respect to Great Lakes hydropower are aimed at supplying energy to meet demand and supplying it in the most cost effective manner. This is not a simple task. Therefore, many different criteria must be used when evaluating the impacts of the measures being considered under the IJC Water Levels Reference Study.

Economic criteria can be applied to the assessment, but there are many types of costs that may need to be considered. The most important of these is the cost of producing electricity and the overall cost of providing electricity. The cost of providing electricity includes costs for additional capacity, which can include design, construction and acquisition costs, the costs of associated transmission and distribution facilities, environmental impact control costs, operation and maintenance costs, and waste disposal costs (eg. fly ash from coal-fired plants).

The industry also has adopted strategies for implementing demand management programs in an effort to reduce the need to build additional generating capacity. This is another criteria that should be considered in the assessment of impacts, since the costs and effectiveness of such programs may be affected by the measures. For example, measures that reduce the availability of hydropower and increase costs of electricity may increase the willingness of electricity consumers to participate in industry sponsored demand management programs. However, the costs of such participation likely will be comparable to those of supplying energy through other sources.

Other important criteria to be considered in the assessment of measures impacts are customer satisfaction, reliability of supply, public acceptance, flexibility, and business risks. In the case of the New York Power Authority, impacts on its corporate policy of providing low cost hydropower to industries in New York that commit to keeping jobs in the state should be assessed. All of these factors should be considered when evaluating the impacts of a measure or a combination of measures, so that the benefits and costs are equitably distributed among the utilities' customers and the other Great Lakes interests. Ontario Hydro and Hydro-Quebec concur with the views expressed above as they relate to their own provinces.

6.1.2 Thermal Interests

Because of the large number of thermal generators in the basin it has not been possible to obtain a consensus as to the criteria suggested for use in evaluating measures. However, the criteria presented in Section 6.1.1 could be applied to thermal interests.

7. PROCEDURES FOR ASSESSING IMPACTS OF MEASURES ON INTERESTS

7.1 General

This section deals with procedures that could be used to assess the impacts of measures on interests. The intent of Phase I of the Reference was to assess impacts in qualitative terms. It will be necessary in Phase II of the Reference to utilize existing mathematical models to evaluate, for example, the effects of low levels and drought on the capability of primary and sub-class interests to meet power and energy requirements. Models also could be used to evaluate the ability of water-borne transportation to carry raw materials for the thermal interests in the event of low flows and drought. The evaluation methodologies incorporated in these models would have to be reviewed and modified as necessary to reflect current conditions. It might even be helpful and more realistic to analyze or simulate major system perturbations or disturbances using real data from 1987 and 1988. This could be accomplished in cooperation with the New York Power Pool, for example, using a simulator of their control room monitors, much like aircraft simulators used for pilot training.

The several measures to be considered may affect the frequency distribution of lake levels and flows and consequently impact on electric power generation. The impact of measures will be evaluated over the full range of probable lake levels.

7.2 Type I-Measure I.1, Combine Full Regulation of Lake Erie Outflows Via a 50N Scheme

The types of impacts, possible methods of assessment, critique of existing impact assessment procedures and recommended impact assessment procedure associated with this measure include:

a. Reduction in ice and flood problems in the Niagara River due to Lake Erie storms - This measure will eliminate ice runs down the Niagara river due to storms on Lake Erie that historically have caused damage to riparian interests including homeowners and hydropower generators. It also may eliminate flooding on the Niagara River due to seiches, although this will depend upon the height and overall configuration of the structure and whether or not it will be designed to allow for some overtopping. One possible method of assessing the impacts would be to identify the number of historical occurrences and the associated power and energy losses and damages to homeowners since 1964, the first year of operation of the Lake Erie-Niagara River Ice Boom. One shortcoming of the approach is that impacts due to extreme events beyond recorded history are unknown. An appropriate procedure might be to use the historical record to develop a relationship between events and effects, then use the relationship to extrapolate to events of interest.

b. Increase in firm power and total energy output of downstream projects - This measure will allow for the daily management of flows more consistent with the load curves of the existing hydropower projects on the Niagara River. It also will provide for an increase in firm power and total energy resulting from a reduction in the range of high and low levels and flows. The existing models developed in connection with the Lake Erie Regulation Study (LERS) may be adequate, with possibly minor parameter and methodology adjustments, to determine the magnitude of the increases.

c. Lake Erie-Niagara River Ice Boom - This measure will eliminate the need to install the ice boom annually. The boom reduces the amount of ice that moves down the Niagara River due to Lake Erie storms and as a result reduces the negative impacts of ice flows on hydropower interests. The history of costs incurred by the hydropower interests could be used to arrive at a reasonable value to represent this impact.

d. New hydropower capability at the 50N structure - This measure would provide for an increase in power and energy resulting from the possible inclusion of generating capability at the 50N structure. Estimates of the amount of power and energy would have to be developed.

7.3 Type I-Measure I.2, Interbasin Diversions

The types of impacts, possible methods of assessment, critique of existing impact assessment procedures and recommended impact assessment procedure associated with this measure include:

a. Reduction or increase in power and energy - This measure will reduce the amount of firm and secondary power and energy at hydropower projects if the diversions bypass those projects. It will increase power and energy if diversions are brought into the Great Lake system upstream of any given project. The existing models developed for the LERS should be suitable for assessing these impacts.

7.4 Type II-Measure II.1, Barrier Island Construction

The types of impacts, possible methods of assessment, critique of existing impact assessment procedures and recommended impact assessment procedure associated with this measure include:

a. Reduction in flood damages - This measure is expected to reduce flooding of existing hydropower and thermal interests that would result from set-up and waves on top of high lake levels. There are no known methods of impact assessment. It is expected that some form of stage-damage-frequency approach will be suitable for assessment of impacts.

7.5 Type II-Measure II.2, Navigation and Access Channel Dredging/Deepening

The types of impacts, possible methods of assessment, critique of existing impact assessment procedures and recommended impact assessment procedure associated with this measure include:

a. This measure would reduce impacts to thermal primary interests associated with low levels and flows. Ships transporting fuels will have improved access to harbors, other Great Lakes and other mooring points during low water conditions. One possible method of assessment might be to use transportation models used in past IJC studies.

7.6 Recommendations to Improve Impact Assessment

a. It is generally known that the previous studies of the impacts of fluctuating Great Lakes water levels have suffered from a lack of credibility due to the lack of a good inventory of all the interests including electric power, riparians, commercial navigation, recreational boating, environment, etc. A primary objective of this Refenence study is to "establish an analytical capability by which Governments can collectively make decisions to deal with fluctuating water level conditions and identify and analyze certain measures as a basis for bi-national consideration of possible implementation of those measures". To ensure that this objective is met, an inventory of all interests needs to be accomplished/continued and updated on an annual basis. The inventory of electric utilities discussed in this report is based upon data from the period 1985-1987 and some of the information is incomplete (eg. which projects located in the lake counties are actually on/draw water from the Great Lakes or connecting channels).

b. Previous studies have used the historical data bases of levels and flows, commodity transportation, energy usage, etc., to forecast future conditions. The end result is a linearized, smooth representation of what might happen in the future. There is only one thing that can be intelligently stated about the resultant forecast and that is, it has a zero percent chance of occurring. There is a need to use stochastic techniques to develop probability statements about forecasts and then to assess the risks associated with any decision reached using the forecasts. A good example of this is the decision to expend over $100 million dollars to construct pumps to lower the levels of the Great Salt Lake during the last high water period. Even before construction was complete, the lake level went down naturally. Stochastic modeling of the lakes levels coupled with geologic dating of sediments might not have predicted the lowering, but at least there could have been a statement of its probability. Given the current uncertainty of the price of oil or even its supply, COx and acid rain effects, ozone depletion, etc., even a stochastic approach has its drawbacks. However, it is better than nothing and much better than historical, deterministic approaches, unless of course the decision makers can afford to absorb the loss if their decision is incorrect.

c. As mentioned previously, the possibility of simulating major system perturbations or disturbances using real data from 1987 and 1988 and control room monitors, much like aircraft simulators, should be investigated.

8. SUMMARY AND CONCLUSIONS

Individual electric power facilities and the customers they serve, potentially can be impacted by fluctuating levels and flows in various ways. During high water periods, thermal power facilities could experience greater generating efficiency due to lower temperatures of cooling water. Pumping and transportation costs of raw materials also could be reduced. Hydropower outputs in general can be increased with increasing flows and/or head, although there is a threshold of extreme highs above which extra flow cannot be utilized due to physical limitations of equipment and/or hydraulic limitations.

Firm hydropower output decreases if flows fall below long term averages. Thermal power interests would be able to provide make-up power at a higher cost, as long as the decrease in hydropower capacity was not large and demand did not increase significantly. Lower than average water levels are a concern to thermal interests because of the higher probability of exceeding temperature regulations for cooling water discharge, increased cooling water pumping costs, warmer cooling water which adversely affects generating efficiency and increased transportation costs of raw materials obtained by water.

The above impacts potentially may be incurred at individual facilities. However, the power interests are not susceptible to adverse consequences from fluctuating levels as long as those levels do not fall outside the design level of the generating facilities. In essence, the interests have designed their systems, in cooperation with federal regulatory authorities, to be operated over a fairly broad range, taking into account the tradeoff between costs and risks.

Any increase in thermal power generation due to a decrease in installed hydropower output results in negative impacts on the environment. For example, the environment could be negatively impacted due to: increased emissions of greenhouse/acid gases (NOx, COx, SOx) and other atmospheric pollutants (eg. selenium), thermal pollution from cooling water discharge, and the increased need to dispose of solid wastes such as fly ash and spent nuclear fuel. Moreover, the cost of make-up power is several times greater than the cost of the lost hydropower generation.

More severe environmental, social and economic consequences are expected when levels and flows fall below the design levels. Utilities have not designed for this likelihood because it is not economically feasible to do so (Appendix K). Utilities generally do not have drought contingency plans and assume that power can be generated by some other means or obtained elsewhere in the event of a drought. However, other interconnected utilities may be experiencing difficulties meeting their own demands and may not have extra power to sell. The amount of power that can be transmitted between systems also is limited, due to system conditions and transmission line capacity. For example, transmission capability from ECAR to the NPCC during the summer represents only 1.8% of the total NPCC capacity and this may not provide enough make-up power when levels and flows fall below design levels.

Indications of the possible severity of this low flow scenario were observed during the summer of 1988. The NYPP and Ontario Hydro experienced record breaking load demands for a short period of time. Hydropower production was less than in previous years because of lower levels and flows on the Great Lakes and tributaries. Ontario Hydro also had generating units down for maintenance. As a result, Ontario Hydro resorted to public appeals to reduce power demand. The New England Power Pool request for power from the NYPP was denied because of the need to meet demands in New York State. New England utilities instituted voltage reductions to avoid total power outages. Utilities outside the Great Lakes Basin also were affected. For example, a Public Service Co. of Indiana coal-fired plant that is located on a tributary just outside the basin had to temporarily shut down operations last summer in part due to a lack of cooling water. The plant also suffered pump damage due to cavitation and siltation as a result of low water levels. These examples were isolated incidents, but they clearly indicate that during widespread drought conditions, power may not be as reliable as it has been. Furthermore, the effects of more stringent environmental regulations may compound generation problems.

In summary, within a range of fluctuations around the long term averages, the interests can reliably generate electric power to meet current demands with attendant environmental, social and economic impacts. However, in the event of low levels and flows, such as those observed in the 1930's and 1960's, adverse social and economic consequences could be experienced because of widespread brownouts and blackouts. Any increase in thermal power production due to a decrease in installed hydropower output will have a negative impact on the environment.

Structural measures probably would do little to ameliorate the adverse consequences associated with extreme low levels. Representatives from the New York Power Authority, Ontario Hydro and Hydro-Quebec are unsure about the effects of a structural measure such as 50N and associated operational plans in the absence of modelling. However, they did express a desire to participate in the development and evaluation of such a plan. Demand management and public information programs may provide the greatest flexibility to meet possible adverse consequences associated with extreme low water levels.

This work group has found the effects of drought on the electric utility industry in the Great Lakes Basin are potentially severe enough to warrant proceeding with Phase II efforts. The study should continue if for no other reason than to describe physical and environmental processes that are taking place. The public needs to know that there are extremes expected, how extreme conditions might be and the possible non-structural alternatives that could be implemented to help cope with extremes. It also is recommended that the Project Management Team meets soon to develop a plan of study for Phase II and to develop a drought contingency plan to recommend to the Governments.

APPENDIX A

WG7 - ELECTRIC POWER WORK GROUP MEMBERS, INTERESTS, AND SUB-CLASS INTERESTS

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17. Mr. John Haskim, Maintenance Superintendent, Lennox TGS, Box 1000, Highway 33, Bath, Ontario, Canada, KOH 1GO, (613) 352-3525.

18. Mr. David Underwood, Superintendent, Generation Methods & Performance, Niagara Mohawk Power Corp., 300 Erie Blvd. W., Building C-1, Syracuse, NY, 13202, (315) 428-6991, Ext. 3175.

19. Ms. Edith Chase, Information Officer, Ohio Coastal Resource Management Project, P.O. Box 3160, Kent, OH, 44240, (216) 673-1193.

20. Mr. Dave Schweiger, Corps of Engineers, Detroit District, P.O. Box 1027, Detroit, MI, 48231, (313) 226-2395.

21. Mr. Ron Pattison, Edison Sault Electric, P.O. Box 359, Sault Ste. Marie, MI, 49783, (906) 632-2221.

22. Mr. Lawrie Duggan, Great Lakes Power, P.O. Box 100, Sault Ste. Marie, Ontario, Canada, P6A 5L4, (705) 759-7606.

23. Mr. John McLean, Office of Energy Conservation and Environment, Dept. of Public Services, Agency Bldg. #3, Empire State Plaza, Albany, NY, 12333, (518) 474-5368.

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50. Mr. Jean Louis Bisson, Head, Hydrometeorology, Hydro Quebec, Montreal, Quebec, Canada, (514) 289-4093.

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APPENDIX C

LAKE COUNTIES, % OF TOTAL STATE GENERATING CAPACITY
(BY PRIMARY GENERATING SOURCE)

State/ Prov	Energy Source	State/Prov Capacity (MW)	%State/Prov Capacity	Lake Co. Capacity (MW)	%State/Prov Total
WI	Coal	7444	68.2	3634	48.8
WI	Petrol	1225	11.2	120.7	9.8
WI	NatGas	254	2.3	86.8	34.2
WI	Water	414	3.8	32.7	7.9
WI	Ur	1495	13.7	1495	100
WI	Other	86	.8	72	83.7
IN	Coal	18330	95.1	2044	11.2
IN	Petrol	507	2.6	0	0
IN	NatGas	365	1.9	71	19.4
IN	Water	74	.4	0	0
IN	Ur	0	0	0	0
IN	Other	0	0	0	0
IL	Coal	14949	46.7	1595.5	10.7
IL	Petrol	4778	14.9	349.4	7.3
IL	NatGas	707	2.2	368.4	52.1
IL	Water	14	.1	0	0
IL	Ur	11536	36.1	2080	18
IL	Other	0	0	0	0
MN	Coal	5495	63.7	147.5	2.7
MN	Petrol	1144	13.2	130.3	11.4
MN	NatGas	233	2.7	2	.8
MN	Water	139	1.6	15.8	11.4
MN	Ur	1564	18.1	0	0
MN	Other	56	.6	0	0
NY	Coal	3829	12.5	2324	60.7
NY	Petrol	11611	37.9	1859	16
NY	NatGas	5408	17.6	15	.3
NY	Water	5045	16.4	3523.5	69.8
NY	Ur	4768	15.6	2954	62
NY	Other	0	0	0	0
PA	Coal	17526	54.2	118	.7
PA	Petrol	4990	15.4	0	0
PA	NatGas	242	.7	0	0
PA	Water	1869	5.8	0	0
PA	Ur	7666	23.7	0	0
PA	Other	69	.2	0	0

State/ Prov	Energy Source	State/Prov Capacity (MW)	%State/Prov Capacity	Lake Co. Capacity (MW)	%State/Prov Total
OH	Coal	21990	85.3	4104.4	18.7
OH	Petrol	1082	4.2	464.3	42.9
OH	NatGas	386	1.5	55.8	14.4
OH	Water	120	.5	0	0
OH	Ur	2041	7.9	2041	100
OH	Other	154	.6	64	41.6
MI	Coal	12053	53.7	11372.6	94.4
MI	Petrol	3479	15.5	3278.3	94.2
MI	NatGas	698	3.1	190.2	27.2
MI	Water	2192	9.8	2036.2	92.9
MI	Ur	4026	17.9	4026	100
MI	Other	0	0	0	0
Ont	Coal	9039.6	26.3	9039.6	100
Ont	Petrol	2578.3	7.5	2511.4	97.4
Ont	NatGas	352	1	321.7	91.4
Ont	Water	7184.6	20.9	4315.3	60.1
Ont	Ur	15117	44	15117	100
Ont	Other	90.1	.3	75.1	83.3
Que	Coal	0	0	0	0
Que	Petrol	1095.7	3.9	680.4	62.1
Que	NatGas	0	0	0	0
Que	Water	25963.8	92.7	10702.8	41.2
Que	Ur	951.4	3.4	951.4	100
Que	Other	5.4	<0.1	0	0

Notes - data for U.S. States are summer generating capacity. Summer and winter generating capacities are similar at the power plants within the Lake Counties. Summer capacity was therefore used as the representative capacity. Data for Canadian Provinces are gross capacity. Quebec data do not include Churchill Falls. Ontario data include Darlington but not Hearn or Keith (mothballed).

References: 4, 7, 9, 15, 36, 37, 38

APPENDIX D

DISTRIBUTION METHODS OF COAL TO THE ELECTRIC INDUSTRY, BY STATE

Method	State							
	New York	Penn	Ohio	Wiscon	Ind	Ill	Min	Mich
Rail								
Tons	6834	11997	11788	17597	23125	20459	13435	18231
%	86.4	28.0	23.6	92.6	61.1	69.5	98.6	67.0
Truck								
Tons	1059	8722	7970	--	4988	3939	--	4
%	13.5	20.4	15.9	--	13.2	13.4	--	-
River								
Tons	15	11238	22210	1028	9715	2841	166	16
%	0.2	26.2	44.4	5.4	25.7	9.6	1.2	0.1
G.Lak.								
Tons	--	--	23	385	--	55	25	8954
%	--	--	-	2.0	--	0.2	0.2	32.9
Tram	--	10884	7990	--	--	2153	--	--
%	--	25.4	16.0	--	--	7.3	--	--
Total Tons	7908	42481	49981	19010	37828	29448	13626	27203

note: Tons are thousands of short tons and % is of the total tons distributed to the electric industry in the state.
Source: 12

APPENDIX E

QUESTIONNAIRE FOR ELECTRIC UTILITIES

1. Please list individual plants, type of facility, and indicate location on the lakeshore or on a tributary near the lakeshore (include thermal and hydro generating stations and specify water body).

2. Please provide information at the individual plant level about the distribution methods for the primary and alternate energy sources (eg. percentage of coal received by water, rail, truck) and also the source of these materials (eg. company name and/or location).

3. What are the invert elevations of the cooling water intake pipes for the individual plants? At what intake temperature would cooling capacity be impaired? How would this affect generating capacity? (eg. by what percentage could capacity be reduced)?

4. What type of cooling system (eg. direct flow through to lake or river, cooling pond, wet tower) is used at the individual thermal plants?

5. For each thermal plant please indicate the volume of intake water that is consumed in the cooling process (eg. due to evaporation).

6. Were there any difficulties in meeting firm power commitments during the past two summers (1987 and 1988) at any facility?

7. Was there any impact on the cost of generating electricity during the past two summers due to low water levels (eg. increased expense in obtaining raw materials)?

8. If the dry trend continued for several years, what would be the effect? Particular references should be made to raw materials and water availability (eg. for intakes and cooling). Please include a reference elevation below which individual plants might experience problems meeting firm commitments.

9. Has a drought contingency plan been formulated? For example, if hydro capacity was cut back by 50%, could thermal plants (including nuclear) take up the slack? If not, where would the required power be obtained?

10. At what lake or river elevation would there be problems with individual plant flooding? Have these elevations been observed in the past?

11. At high water elevations (eg. elevations higher than those observed in the summers of 1985 and 1986), would there be a problem with receipt or handling of raw materials in the case of thermal facilities or tailwater problems in the case of hydro plants?

12. Is there a high water contingency plan?

13. Please list plants that have had any difficulty in the past two years in meeting regulations governing the temperature of cooling water released to a receiving water body.

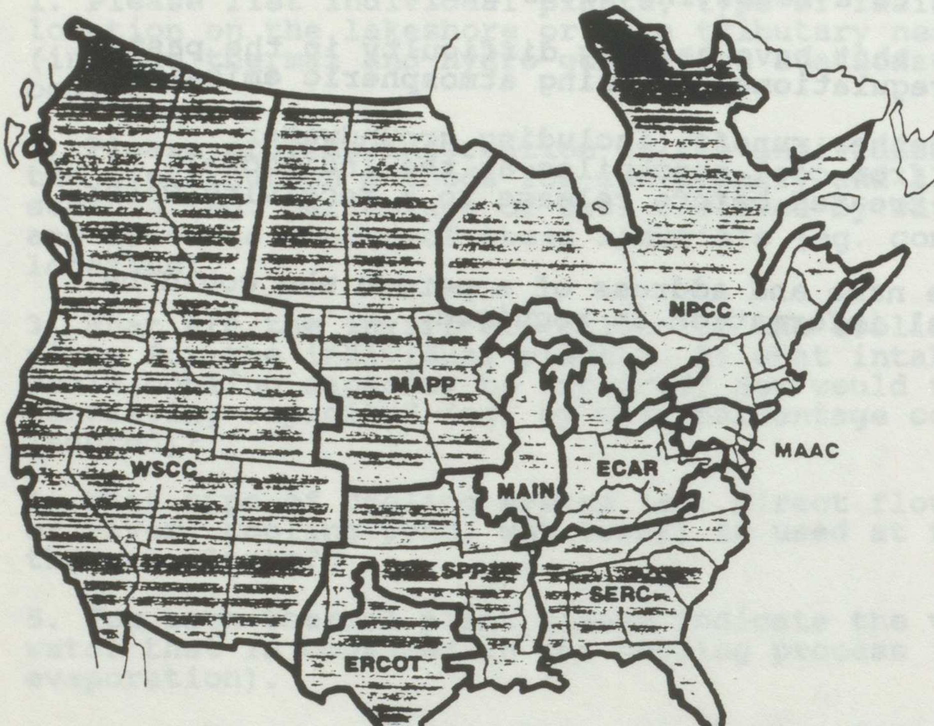
14. Please list plants that have had any difficulty in the past two years in meeting regulations governing atmospheric emissions.

15. Please indicate whether runoff (including groundwater seepage) is collected from coal stockpiles at the individual coal-fired plants and treated before release to a receiving water body.

16. Please provide the name and address of a person who could be contacted if additional information is required.

APPENDIX F

BOUNDARIES OF THE REGIONAL RELIABILITY COUNCILS THAT FORM NERC AND INTERCONNECTION CAPACITIES BETWEEN RELIABILITY COUNCILS



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the electric systems in the United States, Canada, and the northern portion of Baja California, Mexico.

Interconnection Capacities Between Neighboring Reliability Councils

	TRANSFER CAPABILITY-MW	
TRANSFER	SUMMER 1987	WINTER 1987-88
ECAR TO MAAC	600	2000
ECAR TO NPCC (NYPP)	1150	2000
ECAR TO MAIN	4000	4000
ECAR FROM MAAC	4000	4000
ECAR FROM NPCC (NYPP)	2450	3500
ECAR FROM MAIN	4000	4000

Note: Difference between summer and winter transfer capability is due to actual systems conditions including generation dispatch or load distribution, load level, maintenance requirement, etc.
Reference: 51 Similar information for other reliability councils is being obtained.

DESCRIPTION OF INTERPROVINCAL & INTERNATIONAL INTERCONNECTIONS

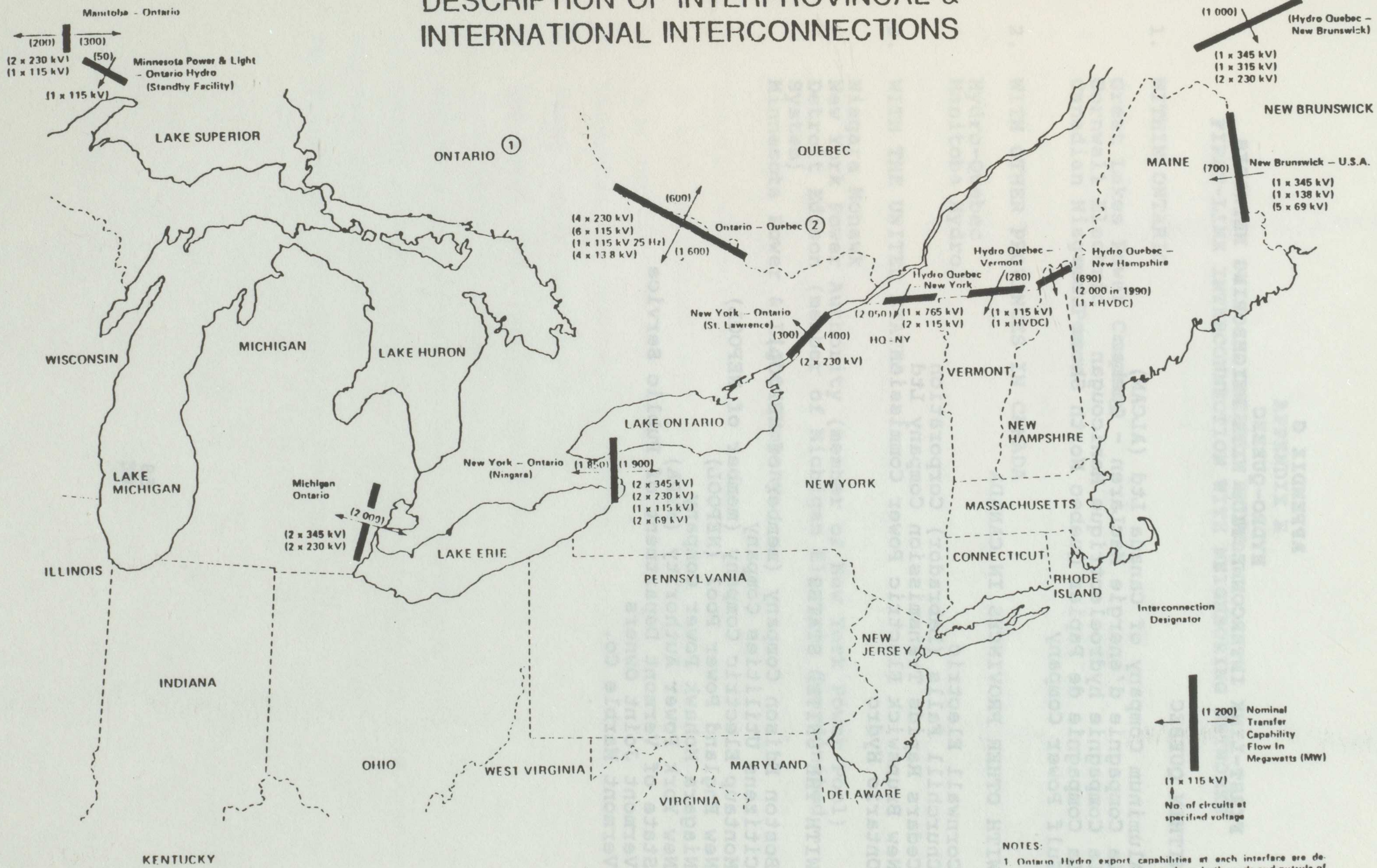


FIGURE 5

NOTES:

1. Ontario Hydro export capabilities at each interface are dependent on flows on other interfaces both inside and outside of Ontario. Therefore, the total Ontario Hydro sales capability is not necessarily equal to the sum of the individual transfer capabilities and some of the individual transfer capabilities indicated may not be achievable due to external conditions.

2. For reasons of system stability, Hydro Quebec cannot operate synchronously with the Ontario Hydro system. Transfers of energy must be effected by isolating generation and/or load from one system to another.

APPENDIX G

HYDRO-QUEBEC
FIRST-LINK INTERCONNECTION WITH NEIGHBORING NETWORKS

1. WITHIN QUEBEC

   Aluminum Company of Canada Ltd (ALCAN)
   La Compagnie d'energie MacLaren - Quebec
   La Compagnie hydroelectrique Manicougan
   La Compagnie de Papier Quebec North Shore Ltee
   Gulf Power Company

2. WITH OTHER PROVINCES IN CANADA

   Cornwall Electric
   Churchill Falls (Labrador) Corporation
   Cedars Rapids Transmission Company Ltd
   New Brunswick Electric Power Commission
   Ontario Hydro

3. WITH THE UNITED STATES

   Boston Edison Company (member of NEPOOL)
   Citizens Utilities Company
   Montaup Electric Company (member of NEPOOL)
   New England Power Pool (NEPOOL)
   Niagara Mohawk Power Company
   New York Power Authority (NYPA)
   State of Vermont Department of Public Service
   Vermont Joint Owners
   Vermont Marble Co.

APPENDIX H

ONTARIO HYDRO
FIRST-LINK INTERCONNECTION WITH NEIGHBORING NETWORKS

1. WITHIN ONTARIO

   Great Lakes Power Company
   Cornwall Electric
   Canadian Niagara Power

2. WITH OTHER PROVINCES IN CANADA

   Hydro-Quebec
   Manitoba Hydro

3. WITH THE UNITED STATES

   Niagara Mohawk
   New York Power Authority (member of New York Power Pool)
   Detroit Edison (member of Michigan Electric Coordinated System)
   Minnesota Power & Light Company

APPENDIX I

NEW YORK POWER AUTHORITY
FIRST-LINK INTERCONNECTION WITH NEIGHBORING NETWORKS

1. WITHIN NEW YORK STATE

   New York State Electric & Gas
   Rochester Gas & Electric
   Niagara Mohawk Power Corp.
   Central Hudson Gas & Electric Corp.
   Con Edison
   Orange & Rockland
   Long Island Lighting Company

2. WITH OTHER STATES

   Public Service Board of Vermont

3. WITH CANADA

   Ontario Hydro
   Hydro-Quebec

APPENDIX J

RESEARCH CONCERNS IDENTIFIED DURING EPRI WORKSHOP
ATLANTA, GA
JANUARY 10-11, 1989

1. Lack of cooling water for thermal power plants.
2. Fossil fuel transportation.
3. Sell generation technologies to foreign countries to improve efficiencies.
4. Educate public.
5. Get the climate/meteorologic information necessary for utility planning.
6. Model end use load shape.
7. Effect of climate change on population distribution.
8. Environmental impacts of demand side management.
9. Alternative regulation options.
10. Societal costs (adapt vs. abate).
11. Pricing strategies which mitigate climate change impacts.
12. Flow quantity intakes.
13. Watershed and reservoir management - competitive uses.
14. Water temperature and quality.
15. Sea level rise - storms, salinity.
16. Sensitivity of streamflow to climate.
17. Validity of forecasting based on historical data.
18. Define natural changing climate, identify long term trends.
19. Real time forecasting.
20. Transmission and distribution line saging.

APPENDIX K

QUESTIONS AND ANSWERS FROM NYPP MEETING
NOVEMBER 15, 1988

I. Existing Facilities

1. Q - Is it possible to list individual plants, type of facility, and indicate location on lakeshore or on a tributary near the lakeshore? Identify waterbody and whether stations are thermal or hydro.
   A - Yes, the individual utilities can be contacted. Other sources of information include the New York State D.E.C. SPDES permits, clean air and water act forms and the NYPP Power Outlook report except for small hydro of less than 2 mW capacity.

2. Q - Is it possible to provide information at the individual plant level about the distribution methods for the primary and alternative energy sources (eg. coal received by water, rail, and truck) and also the source of these materials (eg. company name and/or location)?
   A - Yes, but only for one point in time because the methods and sources change with contract renewals.

3. Q - What are the "efficiency standards", mentioned on page 5 of the NYPP 1988-2004 Electric Power Outlook report, by user group and/or equipment and end-use?
   A - For residential, there are the Federal Appliance Standards of 1987 which are not being implemented until 1990/91. For commercial, the American Society of Heating and Air Conditioning is developing standards. For industry, there is presently no specific program for developing efficiency standards.

   Notes: Expect 1,000-2,500 mW's reduction in demand with 2,000 mW as the most likely by the year 2005 due to efficiency standards. An additional 1,370 mW reduction in summer peak is expected by the year 2004 due to demand management in commercial and residential sectors. Each NYPP member has their demand management plan on file with NYPSC. Some of the types of management factors include shifting demand from on to off peak, thermal storage air conditioning, time of use rates, energy audits, low cost financing of energy conservation measures, etc.

4. Q - How do the "efficiency standards" discussed in the NYPP 1988-2004 Electric Power Outlook report compare with what is feasible using available technology, and what is technically feasible?
   A - Research is continuing into examining the potential gains in technical and end use efficiency.

5. Q - How do the "efficiency standards" discussed in the NYPP 1988-2004 Electric Power Outlook report compare with the customer's present status?
A - Same as question 4. above.

II. Planning Process

1. Q - Has the NYPP's planning considered the potential for climatic change and the need to reduce energy use in general and fossil fuel use in particular?
A - Within the NYPP, the individual members are responsible for planning. Within the electric utility industry, EPRI is conducting research, sponsoring workshops and publishing information on the subjects of acid rain, climate change energy efficiency, etc.. The utilities comply with laws related to pollution but may not be able to recover costs if they go any farther. Planning energy scenarios are based primarily on forecasts of gross state products.

2. Q - Has the planning taken into account climate related feedbacks due to what appears to be acceptance of continued growth in the scale of economic activity and power generation?
A - See answer to 1. above.

3. Q - Is there any cognizance of the environmental crisis facing the earth relative to the planning of future activities?
A - See answer to 1. above.

4. Q - Is there any awareness of the need to think differently and change attitudes toward growth in scale because of the longer term implications of "business as usual"?
A - See answer to 1. above.

5. Q - In this respect, is the real potential for growth in usage efficiency (demand management?) recognized?
A - See answer to 1. above.

6. Q - Considering that there are five Regional Reliability Councils bordering the Great Lakes, how would the NYPP suggest we address the energy transfer and energy values issues from a production optimization standpoint for this large geographic area? Is such a thing possible?
A - This may be possible but needs further investigation. However, at first glance it might be extremely difficult because the total system is complex and dynamic.

7. Q - What are the transmission capability limitations for importing power from adjacent power grids/producers? Is transmission the bottleneck for power exchanges from other regions?
A - This information can be made available when needed. Generally, transmission is a problem between systems, with connections from Quebec and midwest into NY being specifically identified.

8. Q - Does the oil requirements table on page 54, in the NYPP 1988-2004 Electric Power Outlook report, not present any problems in terms of feasibility or advisability?
A - The underlying assumption is that the oil straight line projections do not present a problem. However, concern was expressed over the long term availability and price of oil.

9. Q - How long after 2004 will it be possible to sustain the projected growth in demand for electricity?
A - The NYPP doesn't see why electric consumption isn't sustainable from a fuel availability standpoint. This needs to be further considered.

III. Marketing/Demand

1. Q - What does the market driven conservation discussed in the NYPP 1988-2004 Electric Power Outlook report encompass?
A - Price increases in the market will act to decrease the amount of electricity used given everything else constant.

2. Q - How does market driven conservation compare to the "efficiency standards" mentioned on page 5 in the NYPP 1988-2004 Electric Power Outlook report?
A - Market driven is implicit in the price mechanism. The efficiency standards are imposed externally.

3. Q - What is the implicit discount rate with respect to possible future price increases, and is this discounting too high?
A - The possibility of large future price increases is not taken into consideration.

4. Q - Is it adequate to rely on the market to drive conservation, given its tendency to respond to short run pressures?
A - It is inadequate. However, the utilities perceive that the institutional and regulatory environment forces them to rely on the market.

5. Q - What constitutes the utility sponsored demand side management currently in place as discussed in the NYPP 1988-2004 Electric Power Outlook report?
A - Utility sponsored demand side management consists of the efficiency standards mentioned earlier, and efforts towards peak shifting focused on the residential and commercial sectors. Specifics include energy audits and loans for conservation. Time of use rates are being considered. There is no industrial program.

6. Q - How could utility sponsored demand be improved or combined with other measures?
A - There are possibilities here, however, the utilities themselves, rather than NYPP, should be consulted.

7. Q - Is cogeneration included in utility sponsored demand side management as discussed in the NYPP 1988-2004 Electric Power Outlook report?
A - No. If cogeneration takes place it would be included in the independent power producers group. The utilities do not pursue cogeneration in their customer pool.

IV. Production Model

1. Q - Is there a production/optimization model for the Northeast Power Coordinating Council Region?
A - No. Each individual member/pool has their own.

2. Q - Is there a state-wide or regional electric energy production model available that might be used to assess the economic impact of measures being considered in the IJC study?
A - Yes, given the price of fuel.

3. Q - If such a model exists, what are the principal assumptions of the model and how does it adjust for price level changes?
A - There are no principal assumptions and the model reflects current energy rates available at any given time.

4. Q - What is the geographic scope of the production model?
A - State of New York.

5. Q - Are there any existing links with Ontario Hydro or Hydro-Quebec that are used to optimize energy supply?
A - The NYPP computer programs linked with Ontario Hydro and Hydro-Quebec indicate the amount of energy and the cost at any given time. This information is the basis for NYPP energy purchase decisions and assures reasonable least cost energy is available.

6. Q - Would it be possible, assuming Ontario Hydro and Hydro-Quebec have similar models, to link production models on a large regional basis for study purposes?
A - It would be extremely difficult.

7. Q - Can the general operational criteria and procedures for production model decision making be explained and described?
A - Yes, but it is quite involved.

8. Q - How are plant factor modifications made within the production model. Since many plants are capable of producing additional energy, albeit at a higher price, from a capacity perspective, does the model automatically adjust the plant factor on a mill/kw or other basis?
A - Plant factor is a result of the historical operation and not a model input.

V. Energy Sales And Purchases

1. Q - How are energy sales and purchases consummated? (ie. what are the mechanics?) Are decisions made on an availability, financial, least cost, quid pro quo, etc. basis?
A - Yes.

2. Q - Are there contractual or priority agencies for energy sales/purchase decisions? If so, can this information be made available for the study?
A - Yes, the information is output from the model.

3. Q - Are sales/purchase records for 1988 available for IJC study purposes?
A - NYPP keeps track of energy purchases and sales for total years, but probably doesn't have prices. These may be available from individual utilities.

VI. Drought Planning And Operations (1930, 1988)

1. Q - What might be the effects of ice on hydropower production on the Niagara and St. Lawrence Rivers if a drought similar to that of the 1930's were to occur?
A - Ice might affect cooling water intake abilities. On the Niagara River, Huntley energy output was affected in 1961.

2. Q - Would it be possible to simulate the effects of 12 years of 1930's drought hydrology and temperatures on demand and supply using currently available models?
A - Yes.

3. Q - What was the demand/supply response to the record setting heat wave during the summer of 1988? Did it set summer energy records? All time records? How were energy shortfalls, if any, made up?
A - Summer energy records were set and broken over a few days time. An all time record of 25,300 mW's was set.

4. Q - What was the demand/supply system response to the heat wave and drought in 1988?
A - The load was served. However, the New England Power Pool requests for power could not be filled.

Note: Newspaper accounts in November 1988 indicate that the NE pool also will not be receiving Hydro-Quebec power in the summer of 1989.

5. Q - Can the information from 1988 be used to model system response or dynamics to simulated perturbations of a range of extreme heat/drought events?
A - Yes.

6. Q - What are the system reliability thresholds in terms of various scenarios of these events, and can they be realistically modelled?
A - Beyond obvious thresholds, others would need to be uncovered during simulation runs.

7. Q - Were there any difficulties in meeting firm power commitments during the past two summers (1987 and 1988) at any facility?
A - No.

8. Q - Was there any impact on the cost of generating electricity during the past two summers due to low water levels (eg. increased expense in obtaining raw materials)?
A - Minor cost effect due to shortfalls in hydro needing to be made up by thermal.

9. Q - If the dry trend continued for several years, what would be the effect? Particular references should be made to raw materials and water availability (eg. for intakes and cooling). Please include a reference elevation below which individual plants might experience problems meeting firm commitments.
A - There would be plant specific thermal discharge problems, water use conflicts and salt water intrusion and recirculation problems.

10. Q - Is there a drought contingency plan at the member level of the NYPP? For example, if hydro generation was cut back by 50%, could thermal plants make up the difference? If not, where would the required power come from?
A - No formal plan.

VII. High Water Planning And Operations

1. Q - Is there a high water level contingency plan at the member level of the NYPP?
   A - No.

2. Q - At what lake or river level elevation would there be problems with individual plant flooding? Have these elevations been observed in the past?
   A-This information might be available from the individual members.

3. Q - At high water elevations (eg. elevations higher than those observed in the summers of 1985 and 1986), would there be a problem with receipt or handling of raw materials in the case of thermal facilities or tailwater problems in the case of hydro plants?
   A - There might be some problems in some places. The individual members should be contacted.

VIII. Impact Of Measures Assessment

1. Q - How would the NYPP and the NYPA suggest we determine impacts on energy supply and values for study purposes?
   A - Through modeling. The NYPP could work together with WG 7 on this.

IX. Points Of Contact

1. Q - Can you provide the name and address of a person or persons who could be contacted if additional information is required?
   A - Requests should be forwarded to Mr. Balet who will direct requests to the appropriate person.

QUESTIONS AND ANSWERS FROM ONTARIO HYDRO MEETING
MARCH 2, 1989

I. Production Model

Information provided by: Dave Goulding and Fred Benzaquen

Questions 1,2,6 were answered together. The questions are listed first and the answers are listed subsequently.

1. Q - Is there a province-wide or regional electric energy production model available that might be used to assess the economic impact of measures being considered in the IJC study?
2. Q - If such a model exists, what are the principal assumptions of the model and how does it adjust for price level changes?
6. Q - Can the general operational criteria and procedures for production model decision making be explained?

1,2,6 - A - The production models consider three time frames:

i) near term (today-tomorrow)
ii) a few days to a few weeks
iii) 5-6 years

i) near term - Current conditions are required for this model, including: generation commitments (primary and secondary), transmission ability and water availability. This model is only useful for the short term and is similar to a real-time evaluation of the system. Hour-to-hour scheduling could be examined.

ii) few days to a few weeks - This model considers water flows for a several day to a several week period. Specific data on the current conditions of the system are required.

iii) 5-6 years - This model is used in the operational planning process. It looks at capacity and demand and also provides an operational profile. Model output includes production costs and loads, and this output is used to help establish rate policies. Hourly numbers can be generated by this model, but it was suggested that an examination of monthly values would be sufficient to provide the information we need. This model combines deterministic and stochastic approaches. Load side and resource side information is required for this model, including:

Load Side Information - a profile of firm demands and information on speculative demands.

Resource Side Information - nuclear model - 70,000 gWH assumed available
- planned outages - allowance for forced outages is built in to the production model
- hydraulic model - the current storage in the Great Lakes and other watersheds is required.

It is assumed that flows will return to median flows. Because of this assumption, projections of longer than a year for hydraulic capacity approach a constant. The constant is assumed to be 35,500 gWH, and of this, 2,000 gWH are assumed to be peaking/hydraulic resources (ie. resources that can be moved around).

- fossil model - A probability approach is used to assess how the fossil capability will meet demand. Factors that are considered include the type of fuel, energy production costs, flexibility (eg. in start up time) and timing of demand.

- imports - Imports of energy are used to displace fossil fuel. To meet a shortfall it might be necessary to purchase more expensive electricity.

- transmission considerations - Some capacity is tied up due to transmission limitations (eg. Bruce)

Notes - NUGs are paid on the basis of avoided costs. It is thought that NUGs could provide 1,000 mW or more of power by 2000. It was emphasized that if demand growth continues at the present rate, many utilities in eastern Canada and U.S. will not have enough capacity to meet demand.

3. Q - What is the geographic scope of the production model?
A - The geographic scope is province-wide.

4. Q - Are there any existing links with Quebec, Manitoba, New York or Michigan that are used to optimize the energy supply?
A - Transmission limitations are not explicitly modelled, but power movements are considered. Operationally, existing generating facilities cannot be used to maximize system capability because of transmission limitations (eg. Bruce power is locked in). Special protection schemes are used to increase the power that can be obtained from locked in stations.

7. Q - How are plant factor modifications made within the production model? Since many plants are capable of producing additional energy, albeit at a higher price, from a capacity perspective, does the model automatically adjust the plant factor on a mill/kW or other basis?
A - De-ratings are considered (ie. start up and shutdown), but fossil fuel costs are more difficult to consider.

Notes - Ontario Hydro personnel present did not appear to know about 50N. They would want to know what structure and regulation plans were being considered in order to make comment on the impact to Ontario Hydro. In order to evaluate the impacts of the measures on production, the impacts (eg. the results of a measure) would have to be input to the production model. The model doesn't come up with the impacts.

II. Energy Sales and Purchases

1. Q - How are energy sales and purchases consumated? (ie. what are the mechanics?) Are decisions made on an availability, financial, least cost, quid pro quo, etc. basis?
   A - Agreements are set up for various types of sales. Capacity values are worked out in established agreements; energy values are worked out at the time of sale. Firm export purchases and sales are negotiated individually and are not covered under agreements. Economy sales occur on an hour to hour basis, when the energy is available from other utilities that have excess. Economy sales can be cut off instantly since the energy provided is produced by spinning reserves. The utility generally pays 80% of the avoided costs for energy, although to meet shortfalls they may pay more. Thus, the consumation depends on the type of power needed (ie. long term vs short term, economy or shortfall power).

   Notes - a licence is not needed to sell power within Canada, but a federal licence is needed to sell power outside Canada.

2. Q - Are there contractual or priority agencies for energy sales/purchase decisions? If so, can this information be made available for the study?
   A - Ontario Hydro reports every month to the National Energy Board on exports. The utility is required to sell above cost. The utility can be audited by other utilities to make sure sales costs are correct. In-house audits and audits by Price-Waterhouse are also done.

3. Q - Are sales/purchase records for 1988 available for IJC study purposes?
   A - Yes, although sales/purchases change significantly from year to year, and one year's data would not give an accurate picture of the dynamics of sales and purchases.

III. Drought Planning and Operations

1. Q - Would it be possible to simulate the effects of 12 years of 1930's drought hydrology and temperatures on demand and supply using currently available models?
   A - Yes. The operations models would need the hydrology and hydraulics for input.

   Notes - the 6-8 week freshet period has a large effect on hydraulic generation in Ontario. Approximately 50-60% of Ontario Hydro's energy is of Great Lakes origin. Approximately 40% of the remaining water supply is from freshets.

2. Q - What did the annual load shape factor look like for 1988? Did the summer peak exceed the winter peak throughout most of Ontario? Were record peak loads observed in the summer of 1988 as they were in New York State? How were energy shortfalls, if any, made up?
A - The annual load shape was shown in provided handouts. Record peak loads were observed in the summer of 1988, but the demand was met. Ontario Hydro did have to operate fossil fuel plants to a greater extent than was expected (see also reference 60). There was little power available to be bought from other utilities at this time. The summer peak exceeds the winter around Toronto and Hamilton and also in the London-Michigan corridor, but not in the rest of the province.

3. Q - Were there any difficulties in meeting firm power commitments during the past two summers (1987 and 1988) at any facility?
A - It was emphasized that we shouldn't look at individual facilities, but rather, we should look at the entire system. Ontario Hydro did have to resort to public appeals to reduce demand last summer and this resulted in a demand decrease of 200 mW.

4. Q - How frequently in the past two years did the Ontario Hydro system not maintain its planned 24% reserve capacity?
A - Establishing reserve requirements depends on a number of factors. The reserve requirements may range from 10-12% to 25-30%. Hydraulic dominated utilities would require less reserve because it is possible to get hydraulic plants back on line quicker if maintenance problems occur. The size of the system and the number of large units will also affect reserve requirements. For example, more reserve is required if the system is small but has large units. Ontario Hydro doesn't consider mothballed plants in the determination of reserve. Ontario Hydro has operated during wintertime at 14% reserve.

5. Q - Was there any impact on the cost of generating electricity during the past two summers due to low water levels (eg. increased expense of obtaining raw materials)?
A - Yes, more coal was burned which means electricity was more expensive to produce.

6. Q - Have any plants had difficulty in meeting regulations governing either the temperature of cooling water released to a receiving water body or atmospheric emissions during the last two years? Did any plant shutdowns result?
A - Yes, but refer to (60, 61) for details. Ontario Hydro is committed to reducing acid gas emissions by 50-60% between 1989-1994. Condensor fouling has periodically resulted in unit de-rating.

7. Q - Have any plants experienced adverse impacts on generating capacity due to higher temperatures of intake cooling water during the past two years?
A - Yes, but refer to (53, 61) for details.

8. Q - Can the information from 1988 be used to model system response or dynamics to simulate perturbations of a range of extreme heat/drought events?
A - Possibly, but it may be misleading to use 1988 or any other single year.

IV. High Water Planning and Operations

1. Q - Does Ontario Hydro have a high water level contingency plan?
A - No, except to try and minimize impacts on the environment. Also, concern was expressed over 50N regulation plans, in that flow may be reduced when it is needed and increased when it is not needed (ie. beyond capacity).

2. Q - At high water levels (eg. levels higher than those observed in the summers of 1985 and 1986), would there be a problem with receipt or handling of raw materials in the case of thermal facilities or tailwater problems in the case of hydro plants?
A - It was suggested that there are no real problems.

V. Existing Facilities/Capability of the System

1. Q - Transmission capabilities between Ontario Hydro and Quebec, Manitoba, Michigan and New York?
A - See map provided by Dave Goulding. It was emphasized that it is meaningless to simply add mW capability. Transmission can be highly variable and depends on system conditions.

2. Q - How much electricity is lost in transmission? Is any research being carried out at Ontario Hydro to reduce transmission losses?
A - A 4% transmission loss, on average, is observed over the whole year (higher losses occur at peak times and lower losses occur at non-peak times). In addition a 4% distribution loss, on average, is observed. Research into decreased losses includes: compact conduction, refurbishing line conductors, upgrading voltage of lines, and monitoring the state of superconductivity research. It is not forseen that superconductivity will be important in the near future.

3. Q - What is the status of plans to convert the Lennox plant from oil to coal? Will the Hearn and Keith plants remain mothballed in the near future? Do mothballed or decommissioned plants have to obtain new operating permits in order to start up again?
A - There are no plans to convert Lennox to coal. Currently, there is only one unit that is not operating at the Lennox plant. Hearn and Keith could be brought online, depending on demand. Approval certificates are maintained for mothballed plants and therefore don't have to be re-obtained to bring a plant online again. A certificate update may have to be

obtained if the plant has been changed in any way (eg. oil to coal).

4. Q - It was recently announced that Ontario Hydro will spend $2.5 billion by the end of the century to cut acid emissions from its plants by 60%. Are further reductions planned beyond the year 2000? Are emission standards less stringent for older plants than for plants that would be built in the future? Does Ontario Hydro perceive possible adverse public reaction to increased rates due to retro-fitting scrubbers?
   A - At the moment, Ontario Hydro is decreasing emissions more rapidly than government controls require. It was not known how long this rate of decrease will continue. It was not expected that additional government regulations will be introduced after the year 2000. By law, Ontario Hydro is now limited to 430000 tonnes/year of SOx, NOx emissions and this will be reduced to 250000 tonnes by 1994. Emission standards for older plants are less stringent than for newer plants.

VI. Drought Planning

1. Q - What are the system reliability thresholds in terms of various scenarios of these events, and can they be realistically modelled?
   A - Reliability evaluation is based on the concept of system minutes (ie. peak load interrupted for 1 minute time intervals). 25 system minutes/year is the maximum permissible to meet reliability requirements. Reliability models are available that could be used to evaluate reliability under various scenarios.

VII. Impact of Measures Assessment

1. Q - How would Ontario Hydro suggest we determine impacts on energy supply and values for study purposes?
   A - In order to evaluate measures, Ontario Hydro would want to know what extreme scenarios are to be modelled.

VIII. Planning Procedures

Information provided by Dave Goulding, Paul Burke, Bob McRae and C.K. Jonys.

1. Q - Has Ontario Hydro's planning considered the potential for climatic change and the need to reduce energy use in general and fossil use in particular?
2. Q - Has the planning taken into account possible climate feedbacks due to what appears to be acceptance of continued growth in the scale of economic acitivity and power generation?
   A - Q's 1 and 2 were answered together. Ontario Hydro is

aware of environmental problems, but climatic change considerations are not explicitly accounted for in the current planning process. Ontario Hydro has formed a CO2 task force, and the utility is looking to reduce fossil fuel dependence over the long term to reduce CO2 emissions. Options to reduce fossil fuel dependence are outlined in reference (60).

3. Q - How long after 2005 will it be possible to sustain the most likely projected growth in demand for electricity?
A - Current strategies make it possible to meet reasonable growth rates. The utility will try to stay away from fossil fuels and promote demand side management, nuclear power and NUGs.

4. Q - It is suggested in report 666-SP (p. 4-9) that variations in peak demand due to weather is one of the uncertainties that is taken into account in designing the power system. How is this done?
A - The variations in peak demand due to weather are buried in the total load growth uncertainty for the long term. For the short term, there is a variable allowance of 3%. Generally, short term forecasts are done using weather-normalized data. It is felt that there is not sufficient evidence to build a trend into the weather at this time. The forecast model could take trended data.

Notes: If imports are used to get over a contingency, there is a determined amount of time to get back to reserve after the contingency. Interties can make up shortages on a short 1-2 hour basis, but normal operations require power sales/purchases. Therefore, reliability interties would not be used to get an area through a drought. Long term reliance has to be contracted. It is generally perceived that if a neighbouring utility abuses the intertie system that it will be cut off. Quebec and Ontario are not intertied, they have radial access.

5. Q - It is assumed under the long range load forecast that stability of social, economic and financial institutions will be retained, and that no international crisis will affect the Canadian financial system. How did the stock market adjustment of October 1987 affect demand for electricity? How will free trade affect consumption forecasts?
A - The stock market adjustment really didn't affect demand. A free trade study has been done, and it is predicted that economic growth will be 3% more than without free trade. The growth in electricity demand may be higher than general industrial growth because electric-intensive industries may be favored. The positive effects may not be felt until 1992. Ontario has been moving towards appliance standards, but the province may now take on U.S. standards. Ontario Hydro estimates a 5-6% energy savings could be realized by improving the efficiency of appliance motors.

6. Q - "Resource Smoothing" to reduce peaks and valleys of activity is seen as beneficial to maintaining the flexibility of the system and can lower costs. How do resource smoothing programs work?
A - Resource smoothing is a secondary planning criteria, after the environment, for example. Examples of resource smoothing include: hydraulic - smooth out development, design etc. to get smooth flow; transmission line refurbishment - do it over a period of time, not all at once.

7. Q - Load curves can be smoothed by energy storage or load shifting (Report 666-SP, p. 11-10) but it is noted that storage currently is too expensive to be viable. Is research into storage being pursued?
A - Load shifting is system limited (1000 mW). Shifting is most economically done on the demand rather than the supply side (eg. pumped storage), although Ontario Hydro has looked extensively into above and underground storage. High temperature superconductor storage is being looked at, and some utilities are looking at battery storage, but the latter is not an option actively pursued by Ontario Hydro.

8. Q - Various alternative methods of generation are discussed in Report 666-SP, including independent generation, Integrated Gasification Combined Cycle, wind power and solar power. How actively are these alternative methods of generation being pursued by Ontario Hydro? Will any of these alternatives become an important component of the Ontario Hydro system in the future?
A - Ontario Hydro is particularly interested in integrated gas combined cycle - in which you start off with gas, and if the prices go too high, then you go over to coal gasification. There are wind and solar power demonstrations in Northern Ontario and if continued high growth in demand occurs, these options may become more viable because of short lead times. Gas-fired co-generation is being actively pursued and some projects are currently under construction.

9. Q - Would future thermal (including nuclear) power plants be constructed on the Great Lakes? On tributaries to the Great Lakes?
A - Thermal plants would be located on the shores of the Great Lakes but not on tributaries. Ontario Hydro may be looking at smaller, decentralized plant construction in future planning.

10. Q - Were the low water levels of the 1930's considered in the planning of current hydro and thermal power plants? Are power duration curves available for the major hydropower plants?
A - Thermal and nuclear plants in the Ontario Hydro system were constructed using water level duration curves and the 99% water level was used in the design. The condensor requirements must be fit to water levels. Water level consideration is not as clear for hydraulic projects. Some duration curves were used, but often there was no detailed analysis. Power duration curves can be obtained for the major Niagara and St. Lawrence projects. J.C. Rassam commented

that no one plans using the 1930's drought. It was stated that in general, it would be uneconomical to install additional capacity to accomodate extreme lows (eg. 1930's levels).

IX. Marketing/Demand

1. Q - How were the projections of fertility rate obtained? How was it decided fertility rates will increase in Ontario (Report 666-SP, p. 3-1)?
A - The projections of fertility are, in part, obtained probabilistically and, in part, by judgement looking at an increase in fertility rate of people over 30. It was noted that it is more critical to look at the increase in the labor force when projecting increases in demand. Net migration is also considered when projecting demand increases. Net migration may in fact have a larger impact on demand than birth rate.

2. Q - What type of time series models are used to compile totals for demand?
A - The time series models examine short term and 2-5 year scenarios. The system is called Forecast Master and was developed by EPRI.

3. Q - Can we obtain documentation about the econometric models used for long term demand forecasts?
A - Yes.

4. Q - How would short term and long term forecasting models react to increasing atmospheric temperatures?
A - Price variables for coal and natural gas would have to be adjusted to affect output (ie. for warming).

5. Q - Can we obtain a summary of the surveys done in the late 1970's that asked customers to estimate the costs of power interruptions?
A - Yes, see references (56, 57).

6. Q - It has been suggested in various newspaper reports that Ontario Hydro has a lack of interest in conserving energy. What conservation programs are currently available from Ontario Hydro? In particular, could you discuss public education programs, energy audits, loans or grants for improving efficiency and time differentiated rates?
A - (Bob McRae). Ontario Hydro studies suggest that people will accept increased efficiency in appliances etc. as long as it doesn't inconvenience them. Time of use rates will be important in the industrial sector in the future. Ontario Hydro also promotes technologies such as large hot water heaters to store heat. It is felt that some groups (eg. Energy Probe) don't understand that total efficiency is not possible. Ontario Hydro is looking at a reduction of 4,500 mW in the future due to demand side management. The utility now offers incentives for high efficiency lighting and have

targeted a 20 mW savings. Potentially, there could be a 900 mW savings if all light bulbs in Ontario were replaced, but this is not realistic. Large industrial consumers don't want the utilities to gamble with developing new methods of energy generation and conservation at the expense of conventional technologies. In the past, electric water heating was promoted, but this is no longer the case. It was suggested that electro-technologies are not actively pursued, but Ontario Hydro does provide information when it is needed. It is emphasized that in some cases, even though electric demand is increased, it may displace less efficient (energy-wise) methods or less environmentally sound industrial processes. Ontario Hydro is accelerating demand side management initiatives. The money is there, but the initiatives are still in the growth stage.

7. Q - Has an energy efficiency act been introduced in Ontario?
A - Yes, see handout. It is still not possible to tell manufacturers not to produce inefficient appliances, but the teeth are in the act to get going in this direction. This would be a government and not an Ontario Hydro sponsored action.

8. Q - Could you discuss new electro-technologies that may increase the demand for electricity? Are these tecnologies being actively promoted?
A - Examples include thermo-mechanical pulping, which would increase the electric share of the pulp and paper industry. The steel industry also may have a similar shift. The increase in demand due to all new electro-technologies would only be 1-2%. Electro-technologies are not as actively promoted as they were previously. No financial incentives are provided, although Ontario Hydro may act as a consultant on the technologies.

QUESTIONS AND ANSWERS FROM HYDRO-QUEBEC MEETING
APRIL 19, 1989

I. Marketing

1. Q - What is the current level of Quebec interest in surplus energy? ie. Is Quebec interested in further development of hydropower for the export market in the short term and domestic market consumption in the long range? (p.47)
A - Surplus sales were reduced in 1988 because of low water levels and it is expected that surplus sales will be reduced even further in 1989 (also see diagrams and tables of export sales that were provided by Hydro-Quebec). In general, it is thought that even if average rainfall is experienced over the next couple of years, surplus sales will be reduced in the short term. Last winter, Hydro-Quebec was forced to purchase 800 mW of power from Alcan Aluminum (Que.), New Brunswick and New York. Long term development is oriented toward marketing outside Quebec that maximizes profits from export sales and other advantages offered by interconnections with neighbouring systems. Transmission systems are being improved, in part, to facilitate future exports and this will be particularly important as hydro capacity is added. Some of the additional capacity will be exported for profit. The long term external market sales objectives are in the range of an additional 3500-4500 mW by 2000 (see overhead A82 for the summary of signed agreements for future sales).

2. Q - Briefly explain the current status of the four marketing programs: dual energy heating; industrial rate discounts; boilers; and electro-technologies. (p.6)
A - Dual energy heating is available to the residential, commercial and industrial sectors. This system entails using electric heating in off-peak hours and oil, for example, during peak demand hours. This program is expected to reduce demand by 2000 mW by 1998. A similar dual energy system is available for industrial boilers. The advantages of the dual system for industrial boilers are: i) cheaper electric energy can be used and therefore savings are incurred during off-hours, but the strain on the electric supply is not significantly increased during peak hours; and ii) a possble reduction in demand. Industrial rate discounts were available in the early 80's when there was surplus electricity. The discounts were used to encourage immediate industrial growth in the province, but such discounts are no longer available. However, flexible rates are offered to metals companies (ie. higher rates in good economic times, lower rates in bad times). There are no such schemes for the pulp and paper industry. Electrotechnologies are promoted if the technologies improve energy efficiency. The more efficient technologies may replace other energy sources (eg. oil) that are less environmentally acceptable and finite (ie. non-renewable) in nature. An interruptible power program also is being promoted. It is expected that this program could reduce demand by 2000 mW.

3. Q - What are the near term industrial energy growth sectors? ie. paper-pulp; smelting; etc.
A - The three main industrial growth sectors are pulp and paper, smelting operations (Al, Mg) and chemical production. In particular, new thermo-mechanical pulp and paper techniques are electricity intensive, but also involve a more efficient use of wood and reduce the amount of chemical waste produced. Availability of wood in Quebec is becoming a constraint to pulp and paper production at this time.

4. Q - What is the current management philosophy or policy regarding exports of firm, secondary, and instantaneous energy, especially in light of increased internal consumption?
A - As noted in #1, on the short term, surplus sales are being reduced. Transmission reliability improvement is currently a primary concern of Hydro-Quebec. Exports are expected to increase on the long term.

5. Q - How will the widespread blackouts experienced in the last year affect Hydro-Quebec's current and/or planned power exports?
A - The design criteria in the past for Hydro-Quebec transmission lines has not been as stringent as for thermal systems because the hydraulic system can get back on line more quickly. Hydro-Quebec now has a program to improve the transmission system ($2.3 billion to be spent over the next 10 years on transmission improvement). It was felt, however, that major customers know that Hydro-Quebec has different reliability criteria and should have taken this into consideration when purchasing the power.

6. Q - What energy conservation measures has Hydro-Quebec promoted in recent years, by customer group, customer efficiency status, and/or equipment and end-use? Does Hydro-Quebec market conservation as aggressively as consumption?
A - Conservation programs include promotion of more efficient lighting, dual energy heating systems, improved efficiency water heaters, variable speed motors, etc.

7. Q - Why does Hydro-Quebec feel that conservation gains will be more difficult to achieve in the future (Horizons Report)? Can this statement be supported by showing that available technology, technical feasibility, and overall potential for growth in efficiency in use are essentially exhausted?
A - It is believed that conservation gains can still be made, particularly with respect to residential heating (eg. R2000 homes) and more efficient lighting. However, it is also believed that the easiest conservation gains have been realized, and we are starting to get into diminishing returns. It was suggested that current conservation gains cost $140/MGH, while current energy rates are only $8-30/MGH.

8. Q - What is meant (p. 39, Horizons Report) by the promotion of wise use of electricity?
A - This refers primarily to the dual energy and interruptible power programs.

II. Planning

1. Q - Given that installed and planned generating capacity is almost all hydroelectric, what are the attitudes and plans of Hydro-Quebec towards the potential for climatic change and the need to reduce energy use?
A - Hydro-Quebec is doing climatic change studies in association with Environment Canada and private consultants. It is thought that the warming associated with a doubling of the CO_2 levels would decrease demand in the winter (ie. lower heating requirements) and increase demand in the summer (ie. greater air conditioning requirements). The net result would be a decrease in demand. Changes on the supply side are not clear. It is thought that a 3-4 TWH reduction would be experienced at the St. Lawrence project due to lower levels. However, there is disagreement between studies whether production would decrease or increase in the northern part of the province. It is believed that if the climatic and associated hydrologic changes were gradual, Hydro-Quebec could adjust to the new conditions.

2. Q - Has the policy of "sustainable development" been included in Hydro-Quebec planning?
A - Yes, sustainable development is an explicit Hydro-Quebec goal (see official policy statements provided at the meeting).

3. Q - How are environmental concerns addressed in the Hydro-Quebec planning policy?
A - Hydro-Quebec employs approximately 280 people to work on environmentally related projects (this includes in-house personnel and consultants), and spends $25 million per year on environmental studies. Environmental policy explicitly includes the concept of sustainable development. A unique aspect of the Hydro-Quebec environmental study plan is the consideration of cumulative environmental effects as well as single project effects. The cumulative environmental effect project began in 1987 and considers the net impact of all Hydro-Quebec development on the environment. In the development of a single project, the most appropriate design that also limits environmental impacts is chosen. Decisions on single projects are made based on environmental as well as economic considerations. The environmental assessment is done in-house, but is subject to inspection by provincial environment officials. Detailed, official environmental policy statements also were provided at the meeting.

4. Q - Are there any plans to change the power mix of Hydro-Quebec (ie. thermal power expansion)?
A - No, although there is a possibility that gas turbines could be constructed in the mid 1990's to meet peaking demands. An alternative to this would be improved demand side management.

5. Q - Is co-generation considered or included in Hydro-Quebec's promotion initiatives?
A - Yes, although at present the producers must come to Hydro-Quebec with proposals since the utility does not solicit co-generation plans. This is the first year that co-generation has been included in the development plan. Producers are paid on an avoided-cost basis.

6. Q - How long after 2001 will it be feasible (or advisable) to sustain accelerated growth?
A - Hydro-Quebec has determined that there are 18000 mW of hydropower that can be economically developed (ie. more economic to develop than thermal power). This power is mainly in the James Bay area. Eight more transmission lines would have to be constructed to get the 18000 mW of power to market. An additional 12000 mW of hydropower could be developed, but it has been determined that it would not be economically feasible to do so under current conditions. It was noted that peaking needs in the mid 1990's may be met by the construction of gas turbines, although demand side management would be an alternative.

7. Q - Would it be possible to substantially reduce capital requirements, and financial and environmental risks by purposefully planning for and bringing about a low growth scenario? Why would such a thing not be done?
A - Hydro-Quebec looks at any justifiable means to avoid building new plants. These decisions are based on avoided costs. Higher demand growth in Quebec may simply result from the latest trends of net immigration to the province, and this is unavoidable.

8. Q - Does Hydro-Quebec have a drought contingency plan? A high water contingency plan?
A - In general, seasonal reserves are maintained at 60 TWH. This value was derived by assuming, for example, 4 years of below normal flow (15 TWH below; 4x15=60); or 5 years x 12 TWH below = 60 TWH. Energy also can be brought back from within the system. For example, if necessary, the dual energy systems could run on oil for an extended period of time. Finally, it was suggested that energy would be obtained from neighbouring systems. There does not appear to be a specific high water contingency plan, although it was not felt that such a plan would be necessary.

III. Financing

1. Q - How are large Hydro-electric facilities financed? ie. National capital markets, International capital markets?
   A - Approximately 30-35% of the financing is done externally and the remainder is done internally.

2. Q - Do U.S. utilities participate in finanacing? ie. ConEdison of New York?
   A - No.

IV. Production Model

1. Q - Is there a province-wide or regional electric energy production model available that might be used to assess the economic impact of measures being considered in the IJC study?
   A - Yes. The various models are used when evaluating different time intervals, from real time to long term (10-20 years). A deterministic approach is used for short term evaluations while a stochastic approach is used for longer term evaluations.

2. Q - If such a model exists, what are the principal assumptions of the model and how does it adjust for price level changes?
   A - It does not adjust for price level changes because Hydro-Quebec basically is a hydraulic system.

3. Q - What is the geographic scope of the production model?
   A - Province-wide.

4. Q - Are there any existing links with Ontario, New Brunswick, New York or New England that are used to optimize the energy supply?
   A - No, but interaction with Alcan Aluminum and Churchill Falls is considered.

5. Q - Would it be possible, assuming Ontario Hydro and the NYPP have similar models, to link production models on a large regional basis for study purposes?
   A - It would be difficult.

6. Q - Can the general operational criteria and procedures for production model decision making be explained?
   A - Yes, when needed.

7. Q - How are plant factor modifications made within the production model? Since many plants are capable of producing additional energy, albeit at a higher price, from a capacity perspective, does the model automatically adjust the plant factor on a mill/kw or other basis?
   A - Plant factors are not considered since the system primarily is hydraulic.

V. Rates

1. Q - What is the Hydro-Quebec management philosophy, mission, or policy as a Provincial Corporation concerning Domestic rates?
A - Hydro-Quebec would like to maintain a 13% return on equity and it is felt that this can be done if rates keep pace with inflation.

2. Q - What is the regulatory procedure for establishing energy rates? Is there an internal/domestic economy rate setting procedure as well as a separate export rate setting procedure?
A - The rates are examined by a parliamentary commission and the rate proposal is then sent to cabinet for approval. International exports are supervised by the National Energy Board.

3. Q - Does the Hydro-Quebec Charter require subsidized, breakeven, low, average cost, marginal cost or other basis for internal, domestic, or export rates?
A - This question was not specifically addressed at the meeting, but Hydro-Quebec indicated that average cost is used in terms of a typical pricing schedule.

4. Q - Does Hydro-Quebec offer subsidized or preferential rates as an economic development incentive?
A - Not at present, although such rates were offered to industry in the 1980's to encourage rapid development. Flexible rates are offered to metals companies (see Marketing question #2 for further details).

5. Q - How does Hydro-Quebec establish customer class rates, ie. residential, commercial, industrial rates?
A - See Hydro-Quebec Bylaw Number 480, Establishing Electricity Rates and Their Conditions of Application. Copies of the bylaw (62 p.) were provided by Hydro-Quebec.

6. Q - What is the current rate schedule for all internal/domestic customer classes?
A - The proportion of production cost recovered in 1988, by customer class was:

   Residential, 0.87; Small (users), 1.24; medium (users), 1.24; large (users), 0.98.

   Proposed rate increases are higher for residences (4.5%) in 1989 than, for example, commercial establishments (4.0%) because residential users are currently paying proportionately less.

VI. Energy Sales and Purchases

1. Q - How are firm energy sales price terms determined?
   A - Firm energy sales are negotiated on an individual basis.

2. Q - How are secondary energy sales prices determined?
   A - Secondary energy sales prices are determined using a spot market formula. This formula considers the type of replaced fuel, the unit price of replaced fuel, the heat values of the replaced fuel and the efficiency of the different power generating units (see Hydro-Quebec Bylaw Number 480).

3. Q - Are pre-negotiated terms, less price, arrangements in place for instantaneous or spot market sales?
   A - Yes.

4. Q - What are current 1989 typical rates, both energy and capacity values, for firm, secondary, and instantaneous sales?
   A - Rates are dependent on ability to generate. At times of low flow, such as last year, the rates are higher.

VII. Water Flows and Existing Capabilities

1. Q - Please comment on the following summary:

   St. Lawrence River hydro-electric facilities optimum design capacity, it could be argued, is a function of river base flows plus probability-based additional flows up to the point where the marginal construction cost equalled marginal revenue.

   Capacity and energy above base flow are dependant upon the possibility, not certainty, of higher than base flow. Probable flows (ie. energy), probable revenues (ie. energy sales) and construction costs are the basis of optimum plant sizing.

   Hydro-Quebec's St. Lawrence River generating plants would not be adversely affected by fluctuating levels and flows because the facilities were designed on the basis of this condition. Obviously, plants would produce less energy with less flow, but production under maximum capacity was fully anticipated and reflected in the optimum design capacity. Hydro-Quebec would benefit from flows above base level but not be harmed by flows below plant capacity.
   A - Hydro-Quebec is concerned about the premise and possible ramifications of this summary statement. The summary is being considered and additional views regarding the summary may be communicated at a later date.

2. Q - How sensitive are St. Lawrence river hydro facilities energy production levels to flow changes?
A - Energy production varies with flow. Design of the St. Lawrence system was based upon a flow range of 220000-290000 cfs. Flows outside that range were not planned for as a result of studies performed in connection with the development of Regulation Plan 1958D. Flows have exceeded the upper bound of the range three times, while the lower bound of the range has always been exceeded. The exceedences of the upper bound resulted in spilled water, and by the Reference definition this constitutes an adverse consequence since the true optimum design capacity was not planned for. If flows in the future fall below the lower bound, the plants also would be adversely affected. A qualitative assessment of the impact of fluctuating GL-St. Lawrence flows on power production (thermal and hydro) was provided by Hydro-Quebec.

3. Q - Are energy rates affected directly or indirectly by fluctuating river flows on the St. Lawrence River?
A - Yes, the cost would be spread out over the whole system.

4. Q - What is the maximum flow capacity of Hydro-Quebec facilities on the St. Lawrence? ie what is the maximum cfs each Hydro-Quebec facility on the St. Lawrence can utilize?
A - Beauharnois - 280000 cfs; Les Cedres - 55000 cfs

5. Q - What operational cfs range does Hydro-Quebec plants produce energy? Is there a minimum cfs below which plants cannot operate?
A - There is no minimum for physical operation, but on the St. Lawrence a minimum of 10000 cfs must be maintained for environmental purposes.

6. Q - The levels and flows of the Great Lakes and St. Lawrence River were low in the 30's and early 60's and high in the early 70's and mid 80's. Did flows in tributaries to the St. Lawrence on which hydro projects are located experience similar trends (eg. Manic)? Were similar trends observed in Northern Quebec and Labrador (eg. at the La Grande and Churchill Falls projects)?
A - The trends in central Quebec appear to be different (plotted annual flows provided). Data are available and the spatial variability of the historic flow record needs to be investigated.

7. Q - Were the low water levels of the 30's (or 60's) considered in the planning of current hydro and thermal power plants?
A - For many projects, the lows of the 60's were considered since these lows were more severe in Quebec than the lows of the 30's. The James Bay project had 10 years of record available (beginning in the early 60's) for planning purposes. In addition, 30 years of record were generated using hydrologic models, correlation and regression with other gauged basins in the area.

8. Q - Could we obtain the energy duration curves, flows and power outputs for the La Grande, Manic and Churchill Falls projects and for Beauharnois?
A - Yes, to be provided.

9. Q - Could we obtain a summary of the transmission capabilities between Hydro-Quebec and utilities in other provinces and states?
A - Yes, see map and information provided.

10. Q - How much electricity is lost in transmission? Is any research being carried out at Hydro-Quebec to reduce transmission losses?
A - Losses of approximately 5% are experienced along the large lines to Montreal. However, the 735 kV lines have reduced losses because of the higher transmission voltage. Research is being conducted to reduce losses and this research includes development of superconductors.

11. Q - What was the demand/supply system response to the heat wave and drought in 1988, to the present?
A - Surplus sales were cut both within the province and externally.

APPENDIX L

INVENTORY OF ELECTRIC POWER INDUSTRY
U.S. AND CANADIAN LAKE COUNTIES

State/ Province	County	Company	Plant	Capacity (MW)	Energy Source	Method of Distr.
Wisconsin	Douglas	Dahlberg	Gordon	0.1x2	water	
		Light&Power		0.4x1	2fo	
		Co.		0.7x1	2fo	
Wisconsin	Manitowac	Manitowac	Manitowac	5.3x2	ng	
			City	5x1	bit	
				10x2	bit	
				22x1	bit	
				32x1	bit	
Wisconsin	Ashland	Northern	Bay Front	21x1	wood	
		States Power		24x1	wood	
		Co.		27x1	wood	
Wisconsin	Ashland	NSPC	White River	0.5x2	water	
Wisconsin	Oconto	Oconto Elec.	Stiles	0.5x2	water	
		Coop				
Wisconsin	Douglas	Superior Water	Winslow	12.5x1	ng	
		Light&Power		12.7x1	ng	
Wisconsin	Door	Washing. Is.	Washington Is.	0.3x2	2fo	
		El. Coop.		0.1x2	2fo	
Wisconsin	Milwaukee	Wisconsin El.	Commerce	31x1	ng	
		Power Co.				
Wisconsin	Milwaukee	WEPC	North Oak	95x2	bit	
			Creek	107x1	bit	
				114x1	bit	
Wisconsin	Oconto	WEPC	Oconto Falls	0.6(total)	water	
Wisconsin	Kenosha	WEPC	Pleasant	580x2	sub	
			Prairie			
Wisconsin	Manitowac	WEPC	Point Beach	485x2	ur	
				16x2	2fo	
Wisconsin	Ozaukee	WEPC	Port	45x1	bit	
			Washington	65x1	bit	
				75x2	bit	
				55x1	bit	
				18x1	2fo	
Wisconsin	Milwaukee	WEPC	South Oak	220x1	bit	
			Creek	245x1	bit	
				280x2	bit	
				20x1	ng	
Wisconsin	Milwaukee	WEPC	Valley	130x1	bit	
				137x1	bit	
				3x1	2fo	
Wisconsin	Marinette	Wisconsin	Caldron Falls	3.5x2	water	
		Pub.Ser.Corp.				
Wisconsin	Marinette	WPSC	High Falls	1.4x5	water	
Wisconsin	Marinette	WPSC	Johnson Falls	2x5	water	
Wisconsin	Kewaunee	WPSC	Kewaunee	525x1	ur	
Wisconsin	Marinette	WPSC	Peshtigo	0.2x1	water	
Wisconsin	Marinette	WPSC	Potato Rapids	0.5x1	water	
				0.4x2	water	
Wisconsin	Brown	WPSC	Pulliam	26.1x1	bit	
				28.3x1	bit	
				52.4x1	bit	
				63.7x1	bit	

A	B	C	D	E	F	G
				75.9x1	bit	
				130.6x1	bit	
Wisconsin	Marinette	WPSC	Sandstone	2.0x2	water	
			Rapids			
Wisconsin	Marinette	WPSC	West	40.3x1	2fo	
			Marinette	40.1x1	2fo	
Indiana	Lake	Commonwealth	State Line	187x1	sub	
		Edison Co.		303x1	sub	
Indiana	Porter	Northern	Bailly	28x1	ng	P
		Indiana Pub.		160x1	bit	RR
		Serv.Co.		320x1	bit	RR
Indiana	Lake	NIPS	D.H.Mitchell	110x1	bit	RR
				125x3	bit	RR
				16x1	ng	P
				12x1	ng	P
				15x1	ng	P
Indiana	La Porte	NIPS	Michigan City	469x1	bit	RR
				60x1	bit	RR
				60x1	bit	RR
Illinois	Cook	Commonwealth	Bloom	11.2x2	2fo	
		Edison Co.		13.5x2	2fo	
				12.8x1	2fo	
				16.1x1	2fo	
				11.9x1	2fo	
				13.2x1	2fo	
Illinois	Cook	CEC	Calumet	14.7x1	ng	
				14.8x2	ng	
				12.3x1	ng	
				14.1x1	ng	
				14.2x3	ng	
				15.1x1	ng	
				13x1	ng	
				13.6x2	ng	
				13.7x1	ng	
				14x1	ng	
				8.3x1	ng	
				15x1	ng	
Illinois	Cook	CEC	Crawford	13.3x1	ng	
				10.9x2	ng	
				14.5x1	ng	
				14.2x1	ng	
				13.7x1	ng	
				11.8x1	ng	
				11.9x1	ng	
				10.8x1	ng	
				10x1	ng	
				13.5x1	ng	
				13.3x1	ng	
				213x1	sub	
				319x1	sub	
Illinois	Cook	CEC	Fisk	316x1	sub	
				2.2x5	2fo	
				20x4	2fo	
				19x1	2fo	
				18x1	2fo	
Illinois	Lake	CEC	Waukegan	24.6x1	2fo	
				29.9x2	2fo	
				28.8x1	2fo	
				100x1	sub	

A	B	C	D	E	F	G
				328x1	sub	
				297x1	sub	
Illinois	Lake	CEC	Zion	1040x2	ur	
Illinois	Cook	Village of	Winnetka	7.5x1	bit	
		Winnetka		5x1	bit	
				10x1	bit	
				2.4x2	2fo	
Minnesota	St.Louis	City of Buhl	Buhl	0.4x1	2fo	
Minnesota	Cook	City of	Grand Marais	0.6x2	2fo	
		Grand Marais		0.7x1	2fo	
				0.2x1	2fo	
				0.1x1	2fo	
				1.1x1	2fo	
				1.2x1	2fo	
Minnesota	St.Louis	Hibbing Pub.	Hibbing	10x1	sub	
		Util. Comm.		1.5x1	sub	
				19.5x1	sub	
Minnesota	St.Louis	Minn. Power&	Fond du Lac	11.8x1	water	
		Light Co.				
Minnesota	St.Louis	MPLC	M.L.Hubbard	25x2	6fo	
				35x1	6fo	
				39x1	6fo	
Minnesota	St.Louis	MPLC	Syl Laskin	41x2	sub	
Minnesota	Lake	MPLC	Winton	2x2	water	
Minnesota	Lake	City of	Two Harbors	2x1	ng	
		Two Harbors		2x1	2fo	
Minnesota	St.Louis	City of	Virginia	5x1	sub	
		Virginia		1x1	bit	
				1.5x1	bit	
				2.5x1	bit	
				8x1	sub	
				16.5x1	sub	
New York	St.Lawrence	City of	Governeur	0.2x2	water	
		Governeur				
New York	Jefferson	Hydro Develop.	Dexter	0.5x2	water	
		Group Inc.		0.2x1	water	
				0.3x2	water	
New York	Jefferson	HDGI	DiamondIsland	0.4x3	water	
New York	St.Lawrence	HDGI	Fowler No.7	0.3x3	water	
New York	St.Lawrence	HDGI	Hailesboro	0.5x2	water	
			No. 3			
New York	St.Lawrence	HDGI	Hailesboro	0.9x1	water	
			No. 4	0.6x1	water	
New York	St.Lawrence	HDGI	Hailesboro	0.5x2	water	
			No. 6			
New York	St.Lawrence	HDGI	Pyrites 1	1.2x1	water	
New York	St.Lawrence	HDGI	Pyrites 2	3.5x2	water	
New York	Jefferson	HDGI	Thersa	1x1	water	
				0.3x1	water	
New York	Chautaugua	City of	S.A.Carlson	25x2	bit	
		Jamestown				
New York	Niagara	NY State	Somerset	662x1	bit	RR
		Elec.&Gas				
New York	St.Lawrence	Niagara	AllensFalls	3.5x1	water	
		Mohawk Power				
		Corp.				
New York	Jefferson	NMPC	Beebee Island	3.3x2	water	
New York	Oswego	NMPC	Bennetts	6.5x2	water	

	A	B	C	D	E	F	G
184				Bridge	7x2	water	
185	New York	Jefferson	NMPC	Black River	1.7x3	water	
186	New York	St.Lawrence	NMPC	Blake	14x1	water	
187	New York	St.Lawrence	NMPC	BrownsFalls	7.4x1	water	
188	New York	Erie	NMPC	C.R.Huntley	1x1	2fo	
189					190x1	bit	T,RR,W
190					85x4	bit	T,RR,W
191					185x1	bit	T,RR,W
192	New York	St.Lawrence	NMPC	Colton	9.5x2	water	
193					9x1	water	
194	New York	Jefferson	NMPC	Deferit	2.9x3	water	
195	New York	Chautaugua	NMPC	Dunkirk	1x1	2fo	
196					185x1	bit	T,RR
197					90x2	bit	T,RR
198					195x1	bit	T,RR
199	New York	St.Lawrence	NMPC	EastNorfolk	3.6x1	water	
200	New York	St.Lawrence	NMPC	Eel Weir	0.3x1	water	
201					0.5x2	water	
202	New York	St.Lawrence	NMPC	Five Falls	23.9x1	water	
203	New York	St.Lawrence	NMPC	Flat Rock	2.5x2	water	
204	New York	Oswego	NMPC	Fulton	0.5x2	water	
205	New York	Orleans	NMPC	Glenwood	0.3x1	water	
206					0.2x2	water	
207	New York	Oswego	NMPC	Granby	3.5x2	water	
208	New York	St.Lawrence	NMPC	Hannawa	3.7x2	water	
209	New York	Jefferson	NMPC	Herrings	1.1x3	water	
210	New York	St.Lawrence	NMPC	Heuvelton	0.4x2	water	
211	New York	Oswego	NMPC	High Dam	1x4	water	
212	New York	St.Lawrence	NMPC	Higley	1.1x3	water	
213	New York	Niagara	NMPC	HydraulicRace	0.4x1	water	
214	New York	Jefferson	NMPC	Kamargo	1.6x2	water	
215	New York	Oswego	NMPC	Lighthouse	4x1	water	
216				Hill	3.8x1	water	
217	New York	Oswego	NMPC	Minetto	1.3x5	water	
218	New York	Oswego	NMPC	Nine Mile	2x2	2Fo	
219				Point	610x1	ur	
220					1080x1	ur	
221	New York	St.Lawrence	NMPC	Norfolk	3.8x1	water	
222	New York	St.Lawrence	NMPC	Norwood	2x1	water	
223	New York	Orleans	NMPC	OakOrchard	0.3x1	water	
224	New York	St.Lawrence	NMPC	Oswegatchie	0.4x1	water	
225	New York	Oswego	NMPC	Oswego	1x3	2fo	W,RR,T
226					88x3	6fo	W,RR,T
227					850x1	6fo	W,RR,T
228					632x1	6fo	W,RR,T
229					90x1	6fo	W,RR,T
230	New York	Oswego	NMPC	Oswego Falls	1.5x3	water	
231				East			
232	New York	Oswego	NMPC	Oswego Falls	0.3x5	water	
233				West			
234	New York	St.Lawrence	NMPC	Parishville	2.3x1	water	
235	New York	St.Lawrence	NMPC	Piercefield	1.5x1	water	
236					0.4x1	water	
237					0.6x1	water	
238	New York	Jefferson	NMPC	Sewalls	1x1	water	
239					0.9x1	water	
240	New York	St.Lawrence	NMPC	South Colton	18.5x1	water	
241	New York	St.Lawrence	NMPC	SouthEdwards	1.2x1	water	
242					0.6x1	water	
243	New York	St.Lawrence	NMPC	Stark	23x1	water	
244	New York	St.Lawrence	NMPC	SugarIsland	2x2	water	

245	New York	Oswego	NMPC	Varick	1x5	water	
246	New York	Orleans	NMPC	Waterport	0.4x2	water	
247	New York	St.Lawrence	NMPC	Yaleville	0.3x1	water	
248					0.2x1	water	
249	New York	Oswego	New York Power Author.	Fitzpatrick	794x1	ur	
250							
251	New York	St.Lawrence	NYPA	Moses-Lewiston	2400(total)	water	
252							
253	New York	Niagara	NYPA	Moses Dam	800(total)	water	
254	New York	Wayne	Rochester Gas and Elec.Cor.	Ginna	470x1	ur	
255							
256	New York	Monroe	RGEC	Rochester 2	6x1	water	
257	New York	Monroe	RGEC	Rochester 26	2x1	water	
258	New York	Monroe	RGEC	Rochester 3	80x1	bit	
259					14x1	2fo	
260	New York	Monroe	RGEC	Rochester 5	11x2	water	
261					17x1	water	
262	New York	Monroe	RGEC	Rochester 7	65x2	bit	
263					47x1	bit	
264					80x1	bit	
265	New York	Monroe	RGEC	Rochester 9	15x1	ng	P
266	New York	Jefferson	City of Watertown	Watertown	1.8x3	water	
267							
268							
269	Pennsylvania	Erie	Penn. Elec. Co.	Front Street	15x2	bit	
270					8x1	bit	
271					28x1	bit	
272					52x1	bit	
273							
274	Ohio	Cuyahoga	City of Cleveland	Collinwood	16x1	ng	T
275							
276	Ohio	Cuyahoga	CC	Lake Road	25x3	bit	RR
277					85x1	bit	RR
278	Ohio	Cuyahoga	CC	West41 St.	16x2	ng	T
279	Ohio	Ashtabula	Cleveland El. Illum. Co.	Ashtabula	243x1	bit	RR
280					443x4	bit	T
281	Ohio	Lorain	CEIC	Avon Lake	29x1	2fo	T
282					95x2	bit	RR
283					634x1	bit	RR
284	Ohio	Lake	CEIC	Eastlake	129x3	bit	RR
285					238x1	bit	RR
286					646x1	bit	RR
287					29x1	2fo	T
288	Ohio	Cuyahoga	CEIC	Lakeshore	4x1	2fo	T
289					54x1	6fo	T
290					53x1	6fo	T
291					66x1	6fo	T
292					70x1	6fo	T
293					243x1	bit	RR
294	Ohio	Lake	CEIC	Perry	1185x1	ur	
295	Ohio	Lorain	City of Oberlin	Oberlin	1x1	2fo	
296					0.5x1	2fo	
297					1.8x1	2fo	
298					2.5x1	ng	
299					2.7x1	ng	
300					2.6x1	ng	
301	Ohio	Lorain	Ohio Edison Co.	Edgewater	19x2	2fo	T
302					5x1	bit	T
303					62x1	bit	T
304					103x1	bit	T
305	Ohio	Lorain	OEC	WestLorain	51x2	2fo	

306					64x1	wh	
307	Ohio	Lake	City of	Painesville	8.3x2	bit	
308			Painesville		19.3x1	bit	
309					27.5x1	bit	
310	Ohio	Lucas	Toledo Edison	Acme	7x1	bit	RR
311			Co.		25x1	bit	RR
312					75x1	bit	RR
313					45x1	bit	RR
314					72x1	bit	RR
315					108x1	bit	RR
316	Ohio	Lucas	TEC	Bayshore	16x1	2fo	RR
317					132x1	bit	RR
318					134x1	bit	RR
319					142x1	bit	RR
320					213x1	bit	RR
321	Ohio	Ottawa	TEC	Davis-Besse	856x1	ur	T
322							
323	Michigan	Alpena	Alpena Power	FourMileDam	0.6x3	water	
324			Co.				
325	Michigan	Alpena	APC	Ninth St. Dam	0.4x3	water	
326	Michigan	Alpena	APC	Norway Point	2.8x1	water	
327				Dam	1.2x1	water	
328	Michigan	Leenawee	Village of	Clinton	0.5x2	2fo	
329			Clinton		0.4x3	2fo	
330					2x1	ng	
331	Michigan	Chippewa	Cloverland	Dafter	0.9x3	2fo	
332			Electric Coop		2.5x2	2fo	
333	Michigan	Chippewa	CEC	Detour	2.5x2	2fo	
334	Michigan	Alcona	Consumers	Alcona	4x2	water	
335			Power Co.				
336	Michigan	Allegan	CPC	AlleganDam	0.4x1	water	
337					0.9x1	water	
338					1.2x1	water	
339	Michigan	Muskegan	CPC	B.C. Cobb	52x3	bit	W
340					140x2	bit	W
341	Michigan	Charlevoix	CPC	BigRock	69x1	ur	T
342				Point			
343	Michigan	Manistee	CPC	C.W.Tippy	7x3	water	
344	Michigan	Iosco	CPC	Cooke	3x3	water	
345	Michigan	Bay	CPC	D.E. Karn	255x1	bit	RR
346					260x1	bit	RR
347					628x1	crude	RR
348					638x1	crude	RR
349	Michigan	Iosco	CPC	FiveChannels	3.2x2	water	
350	Michigan	Iosco	CPC	Foote	3.3x3	water	
351	Michigan	Bay	CPC	J.C.Weadock	16x1	ng	P
352					145x1	bit	RR
353					142x1	bit	RR
354	Michigan	Ottawa	CPC	J.H.Campbell	16x1	jetfuel	T
355					259x1	bit	RR
356					350x1	bit	RR
357					787x1	bit	RR
358	Michigan	Monroe	CPC	J.R.Whiting	16x1	jetfuel	T
359					95x2	bit	RR
360					120x1	bit	RR
361	Michigan	Iosco	CPC	Loud	2.2x2	water	
362	Michigan	Mason	CPC	Ludington	312x6	water	
363	Michigan	Van Buren	CPC	Palisades	734x1	ur	T
364	Michigan	Emmett	CPC	Straits	10x1	ng	P
365	Michigan	Wayne	City of	Mistersky	26x1	2fo	W
366			Detroit		41x1	6fo	W

367					47x1	6fo	W
368					58x1	6fo	W
369	Michigan	Wayne	Detroit	BeaconHeating	18x1	ng	P
370			Edison Co.		3x1	2fo	
371	Michigan	St.Clair	DEC	BelleRiver	2x1	2fo	
372					640x1	sub	
373					650x1	sub	
374					3x3	2fo	
375	Michigan	Wayne	DEC	ConnorsCreek	2x1	2fo	
376					60x1	2fo	W
377					150x2	bit	W
378					3x1	2fo	W
379	Michigan	Wayne	DEC	Dayton	2x5	2fo	T
380	Michigan	Monroe	DEC	EnricoFermi	13x2	2fo	
381					1093x1	ur	
382					12x1	2fo	
383	Michigan	St.Clair	DEC	Greenwood	795x1	6fo	P
384	Michigan	Huron	DEC	HarborBeach	2x2	2fo	T
385					103x1	bit	W
386	Michigan	St.Clair	DEC	Marysville	33x1	bit	W
387					83x2	bit	W
388	Michigan	Monroe	DEC	Monroe	3x4	2fo	T
389					2x1	2fo	T
390					750x3	bit	RR
391					754x1	bit	RR
392	Michigan	Macomb	DEC	Northeast	15x2	ng	P
393					14x2	ng	P
394					18x1	ng	P
395					19x1	2fo	T
396					20x1	2fo	T
397	Michigan	Huron	DEC	Oliver	3x4	2fo	T
398					2x1	2fo	T
399	Michigan	Tuscola	DEC	Putnam	3x4	2fo	T
400					2x1	2fo	T
401	Michigan	Wayne	DEC	RiverRouge	2x1	2fo	T
402					3x3	2fo	T
403					265x1	6fo	
404					239x1	bit	RR
405					252x1	bit	RR
406	Michigan	Wayne	DEC	Slocum	2x1	2fo	T
407					3x4	2fo	T
408	Michigan	St.Clair	DEC	St.Clair	163x1	bit	W
409					19x1	2fo	T
410					2x1	2fo	T
411					3x1	2fo	T
412					162x1	bit	W
413					163x1	bit	W
414					164x1	bit	W
415					335x1	6fo	
416					294x1	bit	W
417					415x1	bit	W
418	Michigan	Wayne	DEC	Trenton	132x1	bit	RR
419				Channel	111x1	bit	RR
420					500x1	bit	RR
421	Michigan	Tuscola	DEC	Wilmot	2x1	2fo	T
422					3x4	2fo	T
423	Michigan	Chippewa	Edison Sault	Edison Sault	0.4x73	water	
424			Elec. Co.		0.3x2	water	
425	Michigan	SchoolCraft	ESEC	Manistique	2x1	2fo	
426					2.8x1	2fo	
427	Michigan	Mackinac	ESEC	St.Ignace	1.4x1	2fo	

	A	B	C	D	E	F	G
428					1.5x1	2fo	
429	Michigan	Ottawa	City of	HarborAvenue	6x1	2fo	P
430			Grand Haven		2.2x1	5fo	P
431					2.5x1	2fo	P
432					4.5x1	5fo	P
433					1x2	2fo	P
434					2.2x1	2fo	P
435	Michigan	Ottawa	City of	J.B.Sims	10x2	bit	W
436			Grand Haven		58x1	bit	W
437	Michigan	Oceana	City of	Hart	1.1x1	2fo	
438			Hart Hydro		1.4x1	2fo	
439					0.6x1	2fo	
440					1.7x1	ng	
441					0.2x2	water	
442	Michigan	Ottawa	City of	J.DeYoung	10.5x1	bit	
443			Holland		20.5x1	bit	
444					27x1	bit	
445	Michigan	Ottawa	City of	Sixth Street	20x1	2fo	
446			Holland				
447	Michigan	Berrien	Indiana&Mich.	Berrien	3.0(total)	water	
448			Elec.Co.	Springs			
449	Michigan	Berrien	IMEC	Buchanan	2.0(total)	water	
450	Michigan	Berrien	IMEC	D.C.Cook	1030x1	ur	
451					1100x1	ur	
452	Michigan	Marquette	City of	F.J.Russell	0.7x1	water	
453			Marquette				
454	Michigan	Marquette	City of	PlantFour	27x1	2fo	
455			Marquette				
456	Michigan	Marquette	City of	PlantTwo	1.9x2	water	
457			Marquette				
458	Michigan	Marquette	City of	Shiras	14x1	bit	
459			Marquette		15x1	bit	
460					44x1	sub	
461	Michigan	Luce	City of	Newberry	2.5x1	2fo	
462			Newberry		0.5x1	2fo	
463	Michigan	Berrien	City of	Niles	0.5x1	water	
464			Niles				
465	Michigan	Huron	City of	MainStreet	0.9x1	ng	
466			Sebewaing		0.8x1	2fo	
467					1.1x4	ng	
468					1.3x1	ng	
469					0.6x1	ng	
470	Michigan	Huron	City of	PineStreet	1.1x2	ng	
471			Sebewaing				
472	Michigan	Tuscola	Thumb Elec.	Caro	1x3	2fo	
473			Coop Mich.		1.5x1	2fo	
474					0.6x1	2fo	
475	Michigan	Huron	TECM	Ubly	0.6x2	2fo	
476					0.7x1	2fo	
477					1x2	2fo	
478	Michigan	GrandTraverse	City of	Bayside	3x1	bit	W
479			Traverse		6x1	bit	W
480					9x1	ng	P
481					14x1	bit	W
482	Michigan	GrandTraverse	City of	Boardman	0.9x1	water	
483			Traverse				
484	Michigan	GrandTraverse	City of	BrownBridge	0.3x1	water	
485			Traverse		0.2x1	water	
486	Michigan	Antrim	City of	ElkRapids	0.2x2	water	
487			Traverse				
488	Michigan	GrandTraverse	City of	Sabin	0.5x1	water	

489			Traverse				
490	Michigan	Delta	Upper	Escanaba	12.7x2	bit	
491			Penninsula				
492			Power Co.				
493	Michigan	Delta	UPPC	Gladstone	23.8x1	2fo	
494	Michigan	Baraga	UPPC	J.H.Warden	17.7x1	bit	
495	Michigan	Houghton	UPPC	Portage	23.8x1	2fo	
496	Michigan	Ontonagon	UPPC	Victoria	6.2x2	water	
497	Michigan	Chippewa	USCE	St.Marys	5.3x3	water	
498			Detroit Dis.	Falls	2x2	water	
499	Michigan	Marquette	Wisconsin	PresqueIsle	25x1	bit	
500			Elec. Power		37.4x1	bit	
501			Co.		55.3x1	bit	
502					56.4x1	bit	
503					84.4x1	bit	
504					84.7x1	bit	
505					80.5x1	sub	
506					83.1x1	sub	
507					82.7x1	sub	
508	Michigan	Menominee	WEPC	WhiteRapids	7.6(total)	water	
509	Michigan	Menominee	Wisconsin	GrandRapids	1.1x2	water	
510			Public Service		1.5x2	water	
511			Corp.		1.4x2	water	
512					1.9x2	water	
513	Michigan	Charlevoix	Wolverine	Advance	7.5x2	bit	W
514			Pwr. Supply		23x1	bit	W
515			Coop Inc.				
516	Michigan	Charlevoix	WPSCI	BeaverIsland	0.5x1	2fo	W
517					0.1x2	2fo	W
518					0.2x1	2fo	W
519					0.4x1	2fo	W
520	Michigan	Allegan	WPSCI	ClaudeVandyke	0.3x1	ng	P
521					0.6x1	ng	P
522					3x1	ng	P
523					22x1	ng	P
524	Michigan	Cheboygan	WPSCI	Kleber	0.6x2	water	
525	Michigan	Mason	WPSCI	Scottville	0.3x3	2fo	T
526					1.1x2	2fo	T
527					1.8x1	2fo	T
528	Michigan	Cheboygan	WPSCI	Tower	18x1	2fo	T
529					1.2x3	2fo	T
530					0.3x2	water	
531	Michigan	Wayne	Wyandotte	Wyandotte	10.5x1	bit	
532			Mun.Serv.Comm.		24x1	bit	
533					7.5x1	2fo	
534					32x1	bit	
535	Michigan	Ottawa	City of	Zeeland	1.4x1	ng	P
536			Zeeland		5.6x1	ng	P
537					6x1	ng	P
538					1.1x1	2fo	
539					1x1	ng	P
540					2x1	ng	P
541					1.7x1	ng	P
542					4.5x1	ng	P
543							
544	Ontario	Algoma	Algoma Steel	Algoma Steel	0.6x2	blast	
545					12.5x2	furnace gas	
546	Ontario	Essex	Allied	Amherstburg	2.5x1	ng	
547			Chemicals		3.8x1	ng	
548					4.7x1	ng	
549	Ontario	Bruce	AtomicEnergy	DouglasPoint	220x1	ur	

	A	B	C	D	E	F	G
550			Canada				
551	Ontario	Lambton	DowChemical	Sarnia	28.8x2	ng	
552	Ontario	ThunderBay	GreatLakes	FortWilliam	4x1	bit	
553					17.1x1	bit	
554					25.5x1	bit	
555					34x1	bit	
556	Ontario	Essex	HiramWalker	Walkerville	1x2	ng	
557					1x2.5	ng	
558					1x5	ng	
559	Ontario	Sudbury	IncoMetals	IronOre	9.4x2	wh	
560				Recovery			
561	Ontario		JamesRiver	Marathon	2x4	spentpulping	
562			Marathon		1x7.5	liquor	
563	Ontario	Bruce	Ontario Hydro	Bruce A	3270(tot)	ur	T
564	Ontario	Bruce	OH	Bruce B	3555(tot)	ur	T
565	Ontario		OH	Lakeview	2400(tot)	bit	W
566	Ontario	Lambton	OH	Lambton	2040(tot)	bit	W
567	Ontario	Lennox/	OH	Lennox	2200(tot)	heavy fuel	R
568		Addington				oil	
569	Ontario	Haldimand/	OH	Nanticoke	4096(tot)	bit	W
570		Norfolk					
571	Ontario		OH	Pickering	4328(tot)	ur	T
572	Ontario	ThunderBay	OH	ThunderBay	423(tot)	ligcoal	W
573	Ontario	Lambton	Polysar	Sarnia	4x1	ng	
574					5x1	ng	
575					13.3x1	ng	
576					28.8x1	ng	
577	Ontario	York	RedpathSugar	Toronto	2.5x1	ng	
578	Ontario	Lennox/	RomanCorp.	Strathcona	3.3(tot)	ng	
579		Addington					
580	Ontario	Hamilton/	Stelco	Hamilton	4x1	blast furnace	
581		Wentworth			6x1	gas	
582	Ontario	Niagara	Tricil	Swaru	4.6x1	shreddedrefuse	
583	Ontario	Leeds	Gananoque	Station6	1.4x2	ng	
584			Light&Power		1.2x2	ng	
585					0.6x2	ng	
586	Ontario	Simcoe	OrilliaWater	Orillia	1x1	diesel	
587			Light&Power		1.1x1	diesel	
588	Ontario	Lambton	DowChemical	Sarnia	54.4x2	ng	
589					72.2x1	ng	
590	Ontario	Bruce	Ontario Hydro	Bruce A	12.1x4	lt.fueloil	
591	Ontario	Bruce	OH	Bruce B	12.1x4	lt.fueloil	
592					4x2	lt.fueloil	
593	Ontario		OH	Lakeview	6.4x3	lt.fueloil	
594	Ontario	Lambton	OH	Lambton	6.4x3	lt.fueloil	
595	Ontario	Lennox/	OH	Lennox	2.5x2	lt.fueloil	
596		Addington					
597	Ontario	Haldimand/	OH	Nanticoke	6.4x3	lt.fueloil	
598		Norfolk					
599	Ontario		OH	Pickering A	5x6	lt.fueloil	
600	Ontario		OH	Pickering B	7x3	lt.fueloil	
601					2.5x2	lt.fueloil	
602	Ontario	Lambton	OH	Sarnia-Scott	15x2	lt.fueloil	
603					16.3x2	lt.fueloil	
604	Ontario	ThunderBay	OH	ThunderBay	11.6x2	lt.fueloil	
605	Ontario	Muskoka	Bracebridge	Bracebridge	0.3x2	water	
606			Hydro	Falls			
607	Ontario	Muskoka	BH	High Falls	0.8x1	water	
608	Ontario	Muskoka	BH	Wilsons Falls	0.6x1	water	
609	Ontario	Northumberland	Town of	Crow Bay	0.9x1	water	
610			Campbellford		1.2x1	water	

611	Ontario	Niagara	Canadian	Rankine	94.7(tot)	water
612			Niagara Power			
613			Co.			
614	Ontario	Sudbury	E.B.Eddy	Espanola	12.7(tot)	water
615			Forest Prod.			
616	Ontario	Leeds	Gananoque	BrewersMills	0.3x3	water
617			Light&Power			
618	Ontario	Leeds	GLP	Gananoque	0.6x1	water
619	Ontario	Leeds	GLP	JonesFalls	0.2x1	water
620					0.8x3	water
621	Ontario		GLP	KingstonMills	0.6x1	water
622					0.8x1	water
623					0.5x1	water
624	Ontario		GLP	Washburn	0.2x1	water
625	Ontario		GreatLakes	AndrewsFalls	38.7(tot)	water
626			Power Co.			
627	Ontario		GLPC	Clergue	18.2x3	water
628	Ontario		GLPC	GartshoreFalls	20x1	water
629	Ontario		GLPC	HighFalls	23.2(tot)	water
630	Ontario		GLPC	Hogg	15x1	water
631	Ontario		GLPC	Hollingsworth	20x1	water
632				Falls		
633	Ontario		GLPC	Mackay	9x2	water
634					22.5x1	water
635	Ontario		GLPC	McphailFalls	5x2	water
636	Ontario		GLPC	ScottFalls	6.8x2	water
637	Ontario	Sudbury	Inco Metals	BigEddy	7x2x2	water
638					6.7x1	water
639	Ontario	Sudbury	IM	HighFalls	3x4	water
640					5.6x1	water
641	Ontario	Sudbury	IM	Nairn	1.5x3	water
642	Ontario	Sudbury	IM	Wabageshik	1.6x1	water
643					2.1x1	water
644	Ontario		Ontario Hydro	Aguasabon	40.5(tot)	water
645	Ontario	ThunderBay	OH	Alexander	65.2(tot)	water
646	Ontario		OH	AubreyFalls	65.2x2	water
647	Ontario	Muskoka	OH	BigChute	4.0(tot)	water
648	Ontario	Muskoka	OH	BigEddy	3.8x2	water
649	Ontario	ThunderBay	OH	Cameron	72(tot)	water
650	Ontario	Sudbury	OH	Coniston	4.1(tot)	water
651	Ontario	Niagara	OH	DecewFalls1	31.9(tot)	water
652	Ontario	Niagara	OH	DecewFalls2	57.6x2	water
653	Ontario	Grey	OH	Eugenia	1.2x1	water
654					2.4x1	water
655	Ontario	Hastings	OH	Frankford	2.6(tot)	water
656	Ontario	Algoma	OH	G.Rayner	42.3(tot)	water
657	Ontario	Northumberland	OH	HaguesReach	3.4(tot)	water
658	Ontario	Muskoka	OH	HannaChute	1.1x1	water
659	Ontario	Northumberland	OH	HeelyFalls	10.5(tot)	water
660	Ontario	ThunderBay	OH	KakabekaFalls	5.4x3	water
661					8x1	water
662	Ontario	Sudbury	OH	McVittie	1.1x2	water
663	Ontario	Northumberland	OH	Meyersburg	1.6x3	water
664	Ontario	ParrySound	OH	Nipissing	1x2	water
665	Ontario	Niagara	OH	OntarioPower	101.4(tot)	water
666	Ontario	ThunderBay	OH	PinePortage	128.7(tot)	water
667	Ontario	Muskoka	OH	RaggedRapids	3.8x2	water
668	Ontario	Northumberland	OH	RanneyFalls	7.9(tot)	water
669	Ontario	Algoma	OH	RedRockFalls	40.5(tot)	water
670	Ontario	Stormont	OH	R.H.Saunders	912(tot)	water
671	Ontario	Northumberland	OH	Seymour	0.6x4	water

	A	B	C	D	E	F	G
672					0.8x1	water	
673	Ontario	Lennox&	OH	Sidney	3.2(tot)	water	
674		Addington					
675	Ontario	Lennox&	OH	SillsIsland	1.3x1	water	
676		Addington			1x1	water	
677	Ontario	ThunderBay	OH	SilverFalls	45x1	water	
678	Ontario	Niagara	OH	AdamBeck1	457.9(tot)	water	
679	Ontario	Niagara	OH	AdamBeck2	1223.6(tot)	water	
680	Ontario	Niagara	OH	AdamBeckP&G	176.7(tot)	water	
681	Ontario	Muskoka	OH	SouthFalls	1.6x2	water	
682					0.6x1	water	
683	Ontario	Sudbury	OH	Stinson	2x2	water	
684	Ontario	Muskoka	OH	TretheweyFalls	1.6x1	water	
685	Ontario	Algoma	OH	Wells	203.3(tot)	water	
686	Ontario	Muskoka	Orillia Water	Matthias	2.8x1	water	
687			Light&Power				
688	Ontario	Muskoka	OWLP	SwiftRapids	2.7x3	water	
689	Ontario	ParrySound	Parry Sound	ParrySound	0.4x1	water	
690			Public. Util.		0.9x1	water	
691	Ontario	Niagara	St.Lawrence	Welland	4x3	water	
692			Seaway Auth.				
693							
694	Quebec	Becancour	Atomic Energy	Gentilly1	266.4x1	ur	
695			of Canada				
696	Quebec	Becancour	Hydro Quebec	Gentilly2	685x1	ur	
697	Quebec		HQ	Tracy	150x4	heavyfueloil	
698	Quebec	Pabok	La Cie	Chandler	6x1	heavyfueloil	
699			Gaspesia Ltee				
700	Quebec	Minganie	Fer et Titane	Havre St.	3.4(tot)	lt.fueloil	
701			du Quebec Inc	Pierre			
702	Quebec	Minganie	Hydro Quebec	Blanc Sablon	8.0(tot)	diesel	
703	Quebec		HQ	Ile-aux-Grues	2.1(tot)	diesel	
704	Quebec	Iles de la	HQ	Iles de la	50.3(tot)	diesel	
705		Madeleine		Madeleine			
706	Quebec	Minganie	HQ	Johan-Beetz	0.6(tot)	diesel	
707	Quebec	Minganie	HQ	La Romaine	0.6x2	diesel	
708					0.8x2	diesel	
709	Quebec	Minganie	HQ	Natashquan	0.8x2	diesel	
710					0.5x1	diesel	
711	Quebec	Minganie	HQ	Port Menier	0.8x2	diesel	
712					0.5x1	diesel	
713	Quebec	Minganie	HQ	SaintAugustin	0.4x2	diesel	
714					0.8x2	diesel	
715					0.6x1	diesel	
716	Quebec	Manicouagan	Hart Jaune	Fifty Foot	48.4(tot)	water	
717			Power Co.	Falls			
718	Quebec	Charlevoix-	Hydro Quebec	Anse St. Jean	0.4x1	water	
719		Est					
720	Quebec	Beauharnois-	HQ	Beauharnois	1645.8(tot)	water	
721		Salaberry					
722	Quebec	La Haute	HQ	Bersimis1	924(tot)	water	
723		Cote-Nord					
724	Quebec	La Haute	HQ	Bersimis2	683.6(tot)	water	
725		Cote-Nord					
726	Quebec	Deux	HQ	Carillon	654.5(tot)	water	
727		Montaignes					
728	Quebec	Francheville	HQ	Grand-Mere	149.6(tot)	water	
729	Quebec		HQ	La Gabelle	136.6(tot)	water	
730	Quebec	Vaudreuil-	HQ	Les Cedres	162(tot)	water	
731		Soulanges					
732	Quebec	Minganie	HQ	Magpie	1.8(tot)	water	

Quebec	Manicouagan	HQ	Manic1	184.4(tot)	water
Quebec	Manicouagan	HQ	Manic2	1015.2(tot)	water
Quebec	Manicouagan	HQ	Manic3	1183.2(tot)	water
Quebec	Manicouagan	HQ	Manic5	1292(tot)	water
Quebec		HQ	Mitis1	6.4(tot)	water
Quebec		HQ	Mitis2	4.2(tot)	water
Quebec	Manicouagan	HQ	Outardes2	453.9(tot)	water
Quebec	Manicouagan	HQ	Outardes3	756.2(tot)	water
Quebec	Manicouagan	HQ	Outardes4	632(tot)	water
Quebec	Montreal	HQ	Riviere des Prairies	48.3(tot)	water
Quebec	La Cote-de-Beaupre	HQ	Sept Chutes	18.7(tot)	water
Quebec	Francheville	HQ	Shawinigan2	182.3(tot)	water
Quebec	Francheville	HQ	Shawinigan3	171.9(tot)	water
Quebec			St. Alban	3.0(tot)	water
Quebec		HQ	St. Narcisse	15.0(tot)	water
Quebec		HQ	St. Raphael	2.6(tot)	water
Quebec		Iron Ore of Canada	SteMarguerite	17.6(tot)	water
Quebec	Manicouagan	La Cie Hydro Manicouagan	MccormickDam	303.8(tot)	water
Quebec	La Haute-Cote-Nord	PapeterieReed	Forestville	1.0(tot)	water
Quebec	Portneuf	PapierJournal Domtar Ltee	Birds	1.9(tot)	water
Quebec	Portneuf	PJDL	MacDougall	2.4(tot)	water

Notes - data for U.S. States are summer generating capacity. Summer and winter generating capacities are similar at the power plants within the Lake Counties. Summer capacity was therefore used as the representative capacity. Data for Canadian Provinces are gross capacity. In most cases the capacity of each generating unit at a plant is given rather than total capacity. For example, 5.3x2 indicates the plant has 2 generators each with a capacity of 5.3 MW. (tot) after the MW capacity indicates total total plant capacity is given rather than individual generator capacity.

Legend for Abbreviations:

Energy Source

bit - bituminous coal	sub - subbituminous coal
ng - natural gas	wh - waste heat
2fo - fuel oil no. 2	lt.fueloil - light fuel oil
6fo - fuel oil no. 6	ur - uranium
crude - crude oil	ligcoal - lignite coal

Method of Distribution

RR - railroad	T - truck
P - pipeline	W - water

APPENDIX M

IDENTIFIED SUB-CLASS INTERESTS

United States - Associations and Parallel Generators

1. New York Public Interest Research Group, 1124 Elmwood Ave., Buffalo, NY, 14222, (716) 885-2315. contact: Ms. Susan Stack.
2. Great Lakes United, 1300 Elmwood Ave., Buffalo, NY, 14222, (716) 886-0142. contact: Mr. Jim Ahl.
3. Ohio Coastal Resource Management Project, P.O. Box 3160, Kent, OH, 44240, (216) 673-1193. contact Ms. Edith Chase.
4. Consolidated Hydro, 2 Greenwich Plaza, Greenwich, CT. contact: P. Brim.
5. Resource Dynamics Corp., 8605 Westwood Center Dr., Vienna, VA, 22180. contact: N. Friedman.
6. Indeck Energy Services Inc., 1111 S. Willis Ave., Wheeling, IL, 60090. contact: L. Kostrzewa, mgr. business development.
7. Bonneville McKenzie, 50-116th Ave. S.E., Suite 201, Bellevue, WA, 98004. contact: R. McKenzie.

United States - Government Agencies

1. Dept. of Public Services, Office of Energy Conservation and Environment, Agency Bldg. #3, Empire State Plaza, Albany, NY, 12333, (518) 474-5368. contact: Mr. John McLean.
2. New York State Energy Office, Agency Bldg. #2, Empire State Plaza, Albany, NY, 12223, (518) 474-2190. contact: J. Dunkleberger, Director, Technical Development Programs.
3. New York State Dept. of Environmental Conservation, 50 Wolf Rd., Albany, NY, 12233, (518) 457-7230.
4. Dept. of Energy, Washington, DC, 20585, (202) 586-8800. contact: Mr. William Jeffers, Office of Information Administration.

Canada - Associations and Parallel Generators

1. Ontario Municipal Electric Association, 2323 Yonge St., Toronto, Ontario, M4P 2C9, (416) 483-7739. contact: E. C. Nokes, executive director.

2. Association of Major Power Consumers, 15 Toronto St., Suite 201, Toronto, Ontario, M5C 2E3. contact: T. B. Lounsbury, executive director.

3. Canadian Electric Association Inc., 1 Westmount Sq., Suite 580, Montreal, Quebec, H3Z 2P9, (514) 937-6181. contact: D. C. Campbell, general manager.

4. Canadian Nuclear Association, 111 Elizabeth St., 11th Floor, Toronto, Ontario, M5G 1P7, (416) 977-6152. contact: N. Aspin, president.

5. Consumers Association of Canada, P.O. Box 9300, Ottawa, Ontario, K1G 3T9, (613) 733-9450. contact: A. Cohen.

6. Energy Probe, 100 College St., Toronto, Ontario, M5G 1L5. contact: A. Turner.

7. Pollution Probe, 12 Madison Ave., Toronto, Ontario, M5R 2S1. contact: C. Isaacs, executive director.

8. Waterpower Association of Ontario, P.O. Box 180, Georgetown, Ontario, L7G 4Y5, (416) 877-5550. contact: R. Dodokin.

9. Independent Power Producer's Society of Ontario, Box 1084, Station F, Toronto, Ontario, M4Y 2T7, (416) 961-7803. contact: J. Brooks, secretary.

10. W.P. London & Associates, Ltd., 4956, Dorchester Road, Niagara Falls, Ontario, L2E 6V9. contact: D. Abraham, VP, marketing.

11. Trent-Severn Waterway, P.O. Box 567, Peterborough, Ontario, K9J 6Z6. contact: F. Alyea, asst. superintendent.

12. Passmore Associates International, 209-135 York St., Ottawa, Ontario, K1N 5T4. contact: D. Argue.

13. Steven R. Friedlich & Associates, 12 Sheppard St., Suite 414, Toronto, Ontario, M5H 3A1. contact: L. Aisterweil, energy management.

14. Canadian Solifuels Inc., 3051 Kennedy Rd., Unit 2, Scarborough, Ontario, M1V 1E7. contact: D. Bar.

15. Consumers Gas Company, P.O. Box 910, Scarborough, Ontario, M1K 5E3. contact: J. Baxter, manager, cogeneration development.

16. Trinity Capital Corporation, 55 University Ave., Suite 310, Toronto, Ontario, M5J 2H7. contact: J. Beatty.

17. Ottawa Engineering Ltd., 2747 Priscilla St., Ottawa, Ontario, K2B 7E1. contact: K. Bennett.

18. ICG Utilities (Ontario) Ltd., 245 Yorkland Blvd., North York, Ontario, M2J 1R1. contact: P. Begenovsky, manager project development.

19. Great Lakes Power, 122 East St., Box 100, Sault Ste. Marie, Ontario, P6A 5L4. contact: E. Black

20. Black River Power Co., P.O. Box 10, Ramore, Ontario, P0K 1R0. contact: D. Boothe, president.

21. Johnston & Buchan, 275 Slater St., Suite 1500, Ottawa, Ontario, K1P 5H9. contact: T. Brett.

22. Canadian/U.S. Utility Investment JVP, 9 Raven Hill, Bedford, Nova Scotia, B4A 3L3. contact: J. Buckingham.

23. Rideau Falls Generating Partnership, P.O. Box 548, 5 King St. E., Gananoque, Ontario, K7G 2V1. contact: H. Campbell.

24. Sundridge Power Corp., 1 York Lane, Norval, Ontario, L0P 1K0. contact: D. Carter.

25. Howden Galt Inc., 1510 Birchmount Rd., Scarborough, Ontario, M1P 2G6. contact: D. Demontmorency, president.

26. Consumers Gas, 100 Simcoe St., Toronto, Ontario, M5H 3G2. contact: F. Dixon, manager new business development.

27. Yellow Falls Power Ltd., 1334 Bodley Rd., Mississauga, Ontario, L8J 3W9. contact: J. Doak.

28. Electogen, P.O. Box 180, Georgetown, Ontario, L7G 4Y5. contact: R. Dodokin.

29. Galetta Power Ltd., P.O. Box 20, RR1, Arnprior, Ontario, K7S 3G7. contact: M. Dupuis.

30. Cobalt Power Company Inc., Island Road, Whitefish, Ontario, P0M 3E0. contact: C. Gatten, president.

31. Connaught Laboratories Ltd., 1775 Steeles Ave., W., Willowdale, Ontario, M2R 3T4. contact: H. Gilbert.

32. Upper Thames River Conservation Authority, P.O. Box 6278, Station D, London, Ontario, N5W 5S1. contact: R. Gold.

33. Pembroke Electric Light Co., 2 St. Clair Ave., E., Suite 700, Toronto, Ontario, M4T 2T5. contact: H. Goldgut.

34. Shaw Industries Ltd., 25 Bethridge Rd., Rexdale, Ontario, M9W 1M7. contact: G. Graham, business development manager.

35. Kimberly-Clark, General Delivery, Terrace Bay, Ontario, P0T 2W0. contact: L. Grayham, director.

36. Trans Canada Pipelines, P.O. Box 54, Commerce Court W., Toronto, Ontario, M5L 1C2. contact: F. Greflund.

37. Bonneville McKenzie, 1 First Canadian Place, #5900, Toronto, Ontario. contact: H. Hall, VP development.

38. Multistream Power Corp., 20 Queen St. W., Suite 1104, Toronto, Ontario, M5H 2V3. contact: S. Headford.

39. Dundas Power Lines, RR1 Chesterville, Ontario, K0C 1H0. contact: F. Herkins, president.

40. Trans Alta Energy Systems, 110 12th Ave., SW, Calgary, Alberta, T2P 2M1. contact: J. Howard.

41. Chapleau Cogeneration Ltd., P.O. Box 1346, Chapleau, Ontario, P0M 1K0. contact: W. Ivey, president.

42. Blue Apple Consulting, 23 Briarwood Rd., Unionville, Ontario, L3R 2W7. contact: B. Jones.

43. Cogeneration Associates Ltd., 250 Bloor St., E., #1411, Toronto, Ontario, M4W 1E6. contact: A. Juchymenko.

44. Cumming-Cockburn, 145 Sparks Ave., Willowdale, Ontario, M2M 2S5. contact: J. Juffs.

45. Winter Associates, 4255 Sherwoodtowne Blvd., Mississauga, Ontario, L4Z 1Y5. contact: D. Kerr, Environmental Planner.

46. Carlisle Limited Partnership #1, 36-338 Hayhurst Rd., Brantford, Ontario, N3R 6Y9. contact: R. Kuiper.

47. Colautti Construction Ltd., Box 908, RR5 Gloucester, Ontario, K1G 3N3. contact: D. Kurosky.

48. Dupont Canada Inc., P.O. Box 611, Maitland, Ontario, K0E 1P0. contact: C. Laidley.

49. Union Gas Ltd., 50 Keil Dr., N., Chatham, Ontario, N7M 5M1. contact: M. Lensink.

50. Barclays Bank of Canada, Roy, Tr. Twr., P.O. Box 9, TD Center, Toronto, Ontario, M5K 1A1. contact: M. Lough, credit manager.

51. Lavalin Inc., 1100 Dorchester Blvd., W., Montreal, Quebec, H3B 4P3. contact: J. Mailhot, president.

52. Marsh Hydro Power Inc., 118 West St., P.O. Box 7, Port Colborne, Ontario, L3K 5V7. contact: J. Marsh, president.

53. Tricil Ltd., 470 Kenora Ave., Hamilton, Ontario, L8X 3X8. contact: A. Martineau, manager.

54. Kagawong Power Corp., P.O. Box 15772, Station F, Ottawa, Ontario, K2C 3S7. contact: E. Masbou.

55. Delhi Power Co., 6333 Corwin Cres., Niagara Falls, Ontario, L2G 5Z6. contact: S. Movey, operations manager.

56. ICG Utilities (Ontario) Ltd., 245 Yorkland Blvd., North York, Ontario, M2J 1R1. contact: M. Meacher, project manager.

57. Dominion Power Corp., 2A-4 Charles Walk, Elliot Lake, Ontario, P5A 2A3. contact: P. Mitchell, VP.

58. Turbex International Inc., P.O. Box 805, Barrie, Ontario, L4M 4V5. contact: A. Mohind.

59. Canadian Imperial Bank of Commerce, Head Office, Commerce Court, Toronto, Ontario, M5L 1A2. contact: G. Newson, manager, corporation finance.

60. Ogden Martin Systems Ltd., 2695 North Sheridan Way, Mississauga, Ontario, L5K 2N6. contact: H. Oliviep, VP marketing.

61. Trout Creek Power Corp., 81 Highway #8, Dundas, Ontario, L9H 4V1. contact:M. Parler, VP.

62. RBC Dominion Securities Inc., P.O. Box 21, Commerce Court S., Toronto, Ontario. M5L 1A7. contact: B. Pelech, VP.

63. Pickersgill Power, P.O. Box 277, Teeswater, Ontario, N0G 2S0. contact: A. Pickersgill.

64. Enserve Financial Corp., 2200 Lakeshore Blvd., W., Suite 206, Toronto, Ontario, M8V 1A4. contact: A. Probyn, president.

65. Marsh Engineering Ltd., P.O. Box 7, Port Colborne, Ontario, L3K 5V7. contact: D. Rice.

66. Nichollis Radike, 150 Sheldon Dr., Box 2246, Cambridge, Ontario, N3C 2V8. contact: T. Richardson.

67. Westinghouse Canada Inc., 30 Milton Ave., Hamilton, Ontario, L8N 3K2. contact: A. Robertson, special project manager.

68. Monenco, 155 Rexdale Blvd., Suite 500, Rexdale, Ontario, M9W 5Z8. contact: M. Rowsell.

69. Don Chemical Canada Ltd., 1086 Modeland Rd., P.O. Box 1012, Sarnia, Ontario, N7T 7K7. contact: B. Sawsida.

70. Marathon Ltd., Postal Bag JR, Marathon, Ontario, P0T 2E0. contact: G. Sanderson, electrical superintendent.

71. Power Inc., 1250 Bay St., Suite 200, Toronto, Ontario, M5R 2B1. contact: F. Schwartz.

72. Blaney, McMurtry, Stafells, 20 Queen St., W., Suite 1400, Toronto, Ontario, M5H 2W3. contact: J. Shepard, partner.

73. Grand River Conservation Authority, P.O. Box 729, Cambridge, Ontario, N1R 5W6. contact: A. Smit.

74. Sticker Associates, 38 Waltham Cres., Richmond Hill, Ontario, L4B 1Z6. contact: S. Sticker, president.

75. Northland Power, 11 Church St., Suite 408, Toronto, Ontario, M3C 3M3. contact: J. Temerty, president.

76. Todd Services, 10 Lewis Cres., Kitchener, Ontario, N2A 2T6. contact: W. Todd, turbine tech.

77. SJT Consultants Ltd., 42 Laureleaf Rd., Thornhill, Ontario, L3T 2X7. contact: Dr. S. Townsend.

78. William T. Trick Engineering Inc., Box 1071, RR3 Clinton, Ontario, N0M 1L0. contact: W. Trick.

79. Sandwell Swan Wooster Inc., 29 Gervais Dr., Don Mills, Ontario, M3C 1Y9. contact: Dr. A. Unal.

80. Eastern Power Developers, 2200 Lakeshore Blvd., Suite 206, Toronto, Ontario, M8V 1A4. contact: G. Vogt, VP.

81. Thunder Bay Energy Devel. Corp., 203 County Blvd., Thunder Bay, Ontario, P7A 7P3. contact: R. Whiteside, president.

82. Bank of Montreal, First Canadian Place, 23rd Floor, Toronto, Ontario. contact: T. Whittaker, VP, corp. finance.

Canada - Government Agencies

1. Ministry of Energy, 56 Wellesley St. W., 9th Floor, Toronto, Ontario, M7A 2B7.

2. Ministry of Northern Development and Mines, Box 5000, 435 James St. S., Thunder Bay, Ontario, P7E 6E3. contact: B. Mcilwaine.

3. Ontario Energy Board, 2300 Yonge St., P.O. Box 2319, Toronto, Ontario, M4P 1E4. contact: S. Wychorwanec, chairman.

4. Ministry of Natural Resources, 99 Wellesley St. W., Room 6626, Toronto, Ontario, M7A 1W3.

5. Energy, Mines and Resources Canada, 580 Booth St., Ottawa, Ontario, K1A 0E4. contact: M. Burke, bus. & gov't energy mgmt.